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Design of an Underground Compressed Hydrogen Gas Storage Facility for Use at Fueling Stations

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Design of an Underground Compressed Hydrogen Gas Storage Facility for Use at Fueling Stations

by

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Hydrogen has received significant attention throughout the past decade as the United States focuses on diversifying its energy portfolio to include sources of energy beyond fossil fuels. In a hydrogen economy, the most common use for hydrogen is in fuel cell vehicles. Advancements in on-board storage devices, investment in hydrogen production facilities nation-wide, development of a hydrogen transmission infrastructure, and construction of hydrogen fueling stations are essential to a hydrogen economy. This research proposes a novel underground storage technique to be implemented at a hydrogen fueling station. Three boreholes are drilled into the subsurface, with each borehole consisting of an outer pipe and an inner pipe. Hydrogen gas (H_2) is stored in the inner tube, while the outer pipe serves to protect the inner pipe and contain any leaked gas. Three boreholes of varying pressures are necessary to maintain adequate inventory and sufficient pressure while filling vehicles to full tank capacity. The estimated cost for this storage system is \$2.58 million. This dollar amount includes drilling and completion costs, steel pipe costs, the cost of a heavy-duty hydrogen compressor, and miscellaneous equipment expenses. Although the proposed design

makes use of decades' worth of experience and technical expertise from the oil and gas industry, there are several challenges—technical, economic, and social—to implementing this storage system. The impact of hydrogen embrittlement and the lack of a hydrogen transmission infrastructure represent the main technical impediments. Borehole H_2 storage, as part of a larger hydrogen economy, reveals significant expenses beyond those calculated in the amount above. Costs related to delivering H_2 to the filling station, electricity, miscellaneous equipment, and maintenance associated with hydrogen systems must also be considered. Public demand for hydrogen is low for several reasons, and significant misperceptions exist concerning the safety of hydrogen storage. Although the overall life-cycle emissions assessment of hydrogen fuel reveals mediocre results, a hydrogen economy impacts air quality less than current fossil-fuel systems. If and when the U.S. transitions to a hydrogen economy, the borehole storage system described herein is a feasible solution for on-site compressed H_2 storage.

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CHAPTER 1: INTRODUCTION TO HYDROGEN

Energy drives the world's economies, powering manufacturing and transportation. Access to and use of various energy sources also dictates one's standard of living. Most of the world's energy needs are derived from fossil fuels, or hydrocarbon-rich gas and liquids trapped in reservoirs below the earth's crust. However, developed nations are seeking energy sources beyond conventional fossil fuels for several reasons.

First, harmful effects to the environment and to earth's climate are associated with large amounts of carbon dioxide and pollutants released from burning fossil fuels. In the United States, proposed legislation addressing these concerns passed in the House of Representatives as recently as June 2009, but failed to pass in the Senate.[1] California and several other states have passed similar measures to reduce carbon dioxide emissions and to incentivize development of alternative energy sources, such as hydrogen power. Unpredictable oil price fluctuations, as well as geopolitical issues associated with access to oil and gas contribute to nationwide calls for a decreased reliance on fossil fuels. Furthermore, those who subscribe to the theory of 'peak oil' point to fossil fuels' finite resource as proof of its eventual demise in the world's economies.

Therefore, alternative energy sources are being researched, developed, and implemented. Examples of alternative energy sources include the sun, wind, waves, tides, geothermal, and nuclear. This category also includes biofuels, which are derived from grease, algae, animal fats, ethanol, vegetable oils, domestic refuse, and raw bio mass, such as sawdust, cuttings, wood, grass, and agricultural waste. Hydrogen, like electricity, is a secondary energy source that is converted from a primary energy source. Hydrogen fuels receive more consideration as technologies develop that accommodate such an energy carrier. Although hydrogen has been used for several decades in various applications, widespread use of hydrogen as a fuel source will most likely occur in the transportation sector. Here, hydrogen is burned in an internal combustion engine or used in a fuel cell that powers a vehicle.

A hydrogen economy which offers hydrogen, along-side—or in lieu of—natural gas, liquid gasoline, and diesel, will require large monetary investments to construct H_2-related facilities. The storage of hydrogen represents a complex technical issue because of hydrogen's physical and chemical properties. Research and experimentation have focused more on hydrogen storage vessels in vehicles than on the challenges of storing hydrogen at filling stations.

This work proposes a solution for storing compressed hydrogen gas at filling stations. The unique storage device proposed originates from decades of engineering and technological know-how in the oil and gas industry. Drilling deep holes, 'running casing' down boreholes, and handling high-pressure gas are procedures carried out in the oil field every day. However, using a borehole to store compressed hydrogen gas thousands of feet below filling stations has never been suggested before. While this storage method reveals several challenges, it represents a feasible solution for underground hydrogen storage.

1.1 Properties of Hydrogen

The many difficulties associated with hydrogen storage arise from the nature of the hydrogen molecule. Hydrogen, the lightest and simplest element, has one electron, one proton, and one neutron in its most common form. The hydrogen molecule—pure hydrogen gas—at standard temperature and pressure consists of two hydrogen atoms sharing their valence electrons in a covalent bond, and is written as H_2. Although hydrogen gas is abundant throughout the universe, naturally occurring elemental hydrogen is rare on earth. Hydrogen mostly appears on earth in the form water, H_2O. Due to its propensity to escape from the earth's atmosphere, hydrogen is very difficult to trap. This quality does not bode well for any storage apparatus attempting to contain H_2.[2]

Theoretically, hydrogen can exist as a solid, liquid, and gas. Hydrogen's melting point occurs at a temperature of -434.4 ^{o}F (-259.1 ^{o}C; 14.0 K), and its boiling point occurs at -423.2 ^{o}F (-252.9 ^{o}C; 20.3 K). This small temperature range creates major difficulties for maintaining liquid hydrogen, as does the extremely low temperatures required to maintain solid hydrogen. Hydrogen exists mostly as an odorless, colorless, and highly flammable gas, burning with an invisible flame. By weight, hydrogen has the highest energy content of any common fuel—about three times more than gasoline—but the lowest energy content by volume—about four times less than gasoline.[3]

1.2 Hydrogen Consumption

Despite these characteristics, large quantities of hydrogen are consumed for a variety of uses every day. Liquid hydrogen's explosive power is most well-known as a fuel for launching rockets and other craft into space. The National Aeronautics and Space Administration (NASA) also uses hydrogen to power fuel cells for the shuttle's electrical system. The byproduct provides drinking water for the astronauts.[4] Also, hydrogen is combined with nitrogen to produce ammonia, which is used to fertilize agricultural crops, manufacture plastics, and to make explosives. The components—carbon monoxide and H_2—of synthesis gas, produced from the reaction of coal and steam or from natural gas and steam, is used to make methanol by a catalytic reaction.[5] Methanol is a fuel source and solvent, and used as antifreeze in vehicles. In metal refining, hydrogen aids the extraction of metal from the metal ore by a reduction process. [6]

Significant quantities of hydrogen are used during crude oil refining. Hydrogen gas aides the cracking of hydrocarbons—a process that breaks down long hydrocarbon chains into smaller ones—by removing the sulfur and nitrogen atoms from the hydrocarbon stream. The major products from hydrocracking include jet fuel, diesel, and liquefied petroleum gas (LPG). While fluid catalytic cracking is more common in the U.S. because of its gasoline product, hydrocracking occurs more often in Europe and Asia.[7] De-sulfurization by use of hydrogen-rich gas also occurs in the hydrotreating process. Additionally, hydrogen is added to certain hydrocarbons to produce more desirable hydrocarbon chains, such as naphthenes and alkanes.

1.3 Hydrogen Production

Great demand for hydrogen exists in the oil refining industry, and to a lesser extent in several other industries. The production of hydrogen usually occurs where it is used because of on-site chemical expertise, cost savings, and the lack of infrastructure to transport hydrogen to locations far away. Hydrogen atoms must be separated from other elements. It can be produced from a variety of sources, including water, biomass, fossil fuels, and some algae and bacteria. Hydrogen is also produced as a byproduct of other chemical processes.[8] Each year about 9.9 million tons (9 million metric tons) of hydrogen are produced in the U.S. Most of the production occurs in Louisiana, Texas, and California because of those states' association with oil refining capacity. [9]

Steam reforming is the most common method of producing hydrogen, accounting for about 95% of the hydrogen produced in the U.S.[10] At high temperatures, steam (H_20) reacts with methane and other hydrocarbons to generate synthesis gas. In fact, 188,075 million cubic feet (mmcf) of natural gas was used as feedstock for hydrogen production in 2008. Hydrogen is also a component of synthesis gas (syngas) generated by coal gasification.[11]

Some researchers are considering a co-generation power plant that not only produces electricity from hydrogen, but also captures the plant's carbon dioxide 'waste' for sequestration. For example, Paolo Chiesa and his colleagues propose such a co-generation facility that gasifies coal to syngas, and then shifts syngas in a sour water-gas shift reactor, yielding primarily CO_2 and H_2. Following purification, separation steps, and cooling, the H_2 is burned to produce electricity and the CO_2 is captured for either sequestration or sold to customers for enhanced oil recovery.[12]

Hydrogen production also occurs at small-scale steam reformers. A few small-scale steam reformers are currently under development worldwide using methane, methanol, propane, gasoline, and ethanol to provide hydrogen for use in fuel cells.[13] Some of these reformers use methanol, as discussed above, to produce hydrogen. This process uses catalysts to break apart methanol, yielding hydrogen and carbon monoxide.[14] In a hydrogen economy, owners/operators of filling stations may be able to purchase hydrogen at a cheaper price directly from these micro steam reformers, depending on their proximity and the quantity of these units available. Already in place at various hydrogen filling stations throughout the U.S., Japan, and Germany are small-scale steam methane reformers.[15]

Although not as common and not as energy-efficient, electrolysis represents another method of producing hydrogen. When an electric current is sent through water, the molecule decomposes into its constituent parts—oxygen and hydrogen gas. A compressor internal to the electrolyzer can pressurize hydrogen, eliminating the need and cost of an external compressor. Unfortunately for electrolysis, the power consumed to produce hydrogen is more valuable than the hydrogen itself. Substantial research and development are focusing on using alternative sources of energy, such as photovoltaic solar panels, wind turbines, nuclear, hydropower, and geothermal energy to power electrolysis. Currently, however, these techniques are not competitive with the use of fossil energy for electrolysis. Small-scale electrolyzers are present at several hydrogen filling stations worldwide, used either to supplement hydrogen truck deliveries, or to supply the entire quantity of hydrogen needed.[16]

In a hydrogen economy, the major producers would include those companies that produce the greatest quantities of hydrogen today. Shell, ExxonMobil, BP, ConocoPhillips, Chevron, Citgo, Valero, Marathon, Sunoco, Sinclair, Airproducts, Dow Chemical, and similar companies currently produce the largest amount of hydrogen in the U.S., mainly as a result of the demand for hydrogen in oil refining.[17] However, as the demand for hydrogen grows, smaller companies that use steam reforming or electrolysis would enter the hydrogen-supply market. Perhaps businesses using wind turbines to supply power would be able to use off-peak periods of electricity demand in order to generate hydrogen through co-located electrolyzers.

The major consumers of hydrogen throughout the hydrogen economy would consist of vehicle drivers, vendors, and distributors. With millions of vehicles powered by hydrogen fuel cells or by hydrogen internal combustion engines, the demand for hydrogen would be great. Vendors include mainly filling stations that offer liquid hydrogen or compressed hydrogen gas. If a hydrogen industry follows the pattern of the natural gas industry, distribution companies would become the third major consumers of hydrogen. They would act as the 'middle-man,' negotiating between production facilities and the owners and operators of the two main delivery methods—hydrogen pipelines and tube trailers.

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CHAPTER 2: GAS STORAGE

2.1 Underground Gas Storage

Geologic storage of natural gas provides valuable lessons-learned for similar methods of storing hydrogen. Underground commercial storage of natural gas occurs in salt caverns, in aquifers, and in depleted hydrocarbon reservoirs. Natural gas storage is useful to offset periods of low demand, manage pipeline deliverability, and/or during times of low natural gas prices. Companies in some states utilize natural gas storage more often than others because of climate, population, and market variations throughout the U.S. Additionally, natural gas storage facilities are useful near market centers that do not have adequate gas supply nearby. As of 2007 throughout the U.S., 253,410 mmcf of natural gas was stored in 31 salt caverns, 1,347,516 mmcf was stored in 43 aquifers, and 6,801,291 mmcf was stored in 326 depleted reservoirs.[1]

2.1.1 Salt Structures

Salt domes from salt diapirs—structures that migrate through geologically younger rock layers because of halite's low density—as well as salt beds, created by large ancient evaporite deposits, can be used to store gas. Water injected into the formation helps dissolve these halite structures from within, not only to allow for more storage, but also for mining purposes. Consisting of strong, nearly impermeable walls, salt caverns do not allow gas to escape. The walls of caverns are considered gas tight because the distance between salt lattice units is smaller than the diameter of a methane molecule.[2] Therefore, salt caverns represent reliable, long-term gas storage facilities. Salt domes can have diameters of up to one mile and a height of 30,000 feet, and those used for storage are typically between 1,500 and 6,000 feet below ground surface.[3] Salt beds are usually shallower, thinner, and wider formations. Salt caverns produced from salt formations require less cushion gas than pore storage and hold less volume of gas, but gas injection and extraction is faster. Therefore, salt caverns are used for peak loads, while pore storage is used for base demand requirements.[4] The United Kingdom, because of its growing reliance on natural gas imports and its need to expand storage capacity, has turned a keen eye to onshore halite deposits for storage. Promising formations exist in basins of Permian and Triassic age in the Northeast and Northwest of England, respectively.[5]

2.1.2 Aquifer Storage

Aquifers represent another option for natural gas storage. Many regions of the country must rely more heavily on aquifer storage more so than salt caverns or depleted reservoirs, either because no depleted reservoirs exist nearby or because the ancient depositional environment did not favor the formation of salt structures. Aquifer storage for natural gas is more time consuming to develop, requires higher infrastructure costs, and presents more challenges than the other underground storage options.[6]

Aquifers require significant seismic testing and exploratory wells in order to determine its suitability for natural gas storage. Geological characteristics, such as lithological composition, porosity, location of faults and fractures, and formation pressure must be determined prior to gas injection. Unlike depleted reservoirs, aquifers are formations with fluid—H_2O—remaining in the pores. This requires powerful compressors able to inject gas into an aquifer, which already holds water. Moreover, the gas must be dehydrated once extracted in order to be distributed through pipelines, adding to facilities costs.

Aquifer storage also requires a greater volume of cushion gas than salt caverns and depleted reservoirs. On average, almost eighty percent of the total storage capacity volume of aquifers is cushion gas.[7] This leads to a large of amount of gas that becomes unrecoverable, a costly factor when gas prices are high. Compared to depleted reservoirs, aquifers have poor retention characteristics. Therefore, collector wells must be emplaced in the periphery to capture gas that escapes from the formation. Additionally, due to the possibility of fresh-water contamination, aquifer natural gas storage must comply with more stringent government regulations than depleted reservoir storage.[8]

2.1.3 Depleted Reservoirs

Depleted reservoirs offer a third storage option for natural gas storage. This method of natural gas storage is the most common, the cheapest, and the easiest to develop and operate. A depleted reservoir is a host rock in a subsurface formation which has already been ‘drained’ of its recoverable hydrocarbons. Years after oil and natural gas are produced, methane can be pumped back into the reservoir rock for later use. One clear advantage of depleted reservoir storage is that the geologic conditions, including lithology, structure, reservoir geometry, porosity, and permeability are already known. Another cost-saving advantage of using depleted reservoirs is existing facilities. For example, equipment used in the extraction process and in gas distribution already exists from earlier production. Although “about fifty percent of the natural gas in the formation must be kept as cushion gas,” depleted reservoirs “do not require the injection of what will become physically unrecoverable gas.”[9] Unrecoverable gas already exists in the host rock.

The spatial distribution of depleted reservoir storage facilities depend on the location of producing oil and gas formations throughout the U.S. The closer the facility is to the market, the cheaper the transportation costs. In the U.S., there is a mismatch between the location of storage facilities and populations centers. Figure 2.1 reveals the lack of depleted reservoirs in the Midwest region, including the population center of Chicago, Illinois.

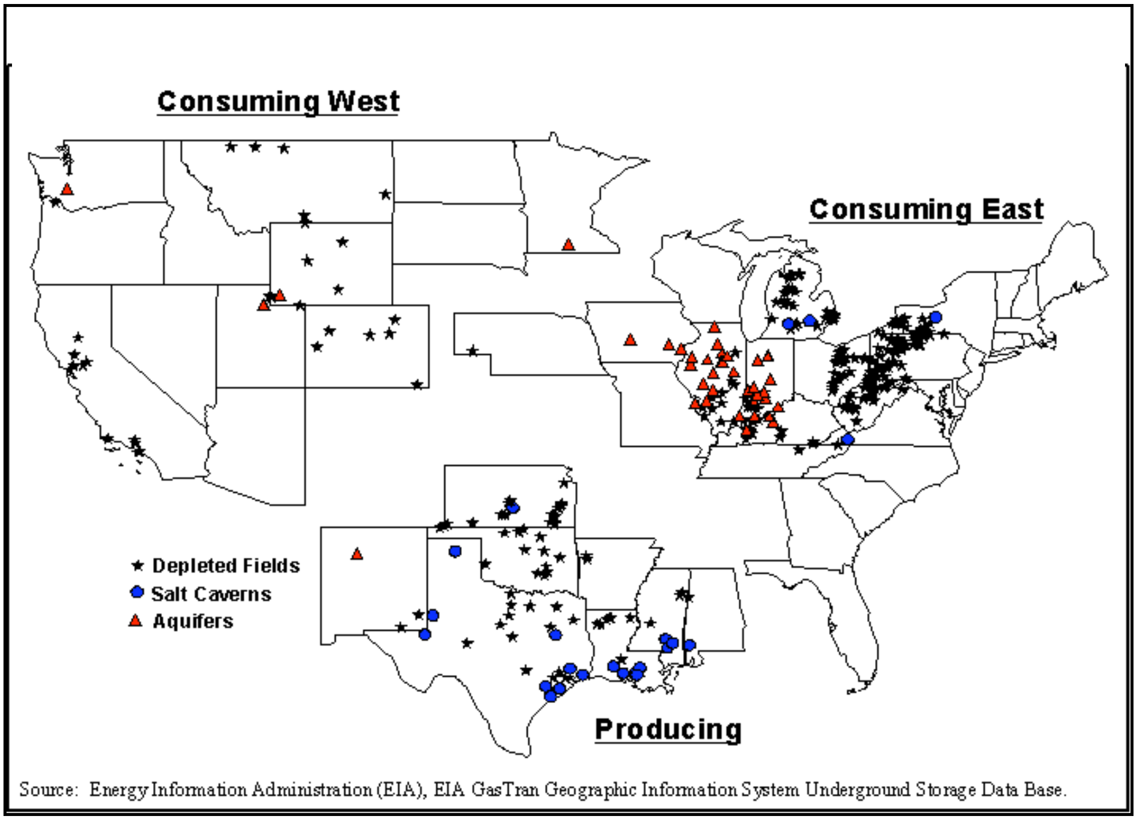

Figure 2.1 Underground natural gas storage facilities in the lower 48 states.[10]

2.2 Hydrogen Storage

Experiences gained from underground natural gas storage shed light on the underground storage of hydrogen. Several underground hydrogen storage projects are currently under development and experimentation. So far, bulk commercial underground hydrogen storage has not been attempted in depleted hydrocarbon reservoirs and aquifers. This most likely results from unknown conditions of hydrogen gas behavior in the subsurface, as well as the high costs associated with containing hydrogen throughout the formation, such as the need for cushion gas or some type of water curtain above the stored gas.

Praxair Technologies and ConocoPhillips are operating hydrogen storage facilities along the Texas Gulf Coast.[11] Phillips' Clemens Terminal, located south of Houston in Brazoria, Texas, has stored hydrogen in a salt cavern since the early 1980s. Praxair operates a 310-mile pipeline which supplies hydrogen from its salt cavern east of Houston to oil refineries and petrochemical plants from Texas City, Texas to Lake Charles, Louisiana.[12] In 2006, Praxair patented a method of injecting hydrogen stored in salt caverns into a pipeline after different compression, extraction and purification steps. As a result of being stored in underground salt caverns, hydrogen gas becomes contaminated. Jeffrey Morrow and two of his colleagues at Praxair invented a way to purify hydrogen gas to various customer specifications and compress it for delivery through pipelines.[13]

Hydrogen is also being stored in the Permian-aged Fordon evaporite formations of Yorskshire, England. This location in Tees County, on the Northeast coast of England, stores over 1,000 tons of compressed hydrogen gas in several solution-mined salt caverns for use in the sprawling petrochemical industry throughout the Tees Valley.[14] As of 2006, over 220 tons (200 tonnes) per day of hydrogen were produced in the Tees Valley from electrolysis, coal, gasification of biomass, and by using surplus wind electricity.[15]

As of April, 2009, there was less than 200 locations worldwide offering hydrogen for fuel. They exist as pre-commercial hydrogen refueling stations and as demonstration projects, funded by federal, state, or municipal government entities, a consortium of public and private enterprises, or wholly funded by organizations in the energy industry.[16] Figure 2.2 depicts operational hydrogen refueling centers in the U.S. as of 2008. The following countries offer one location for hydrogen fueling: Australia, Austria, Iceland, India, Sweden, Switzerland, and Taiwan; the following countries offer two or more hydrogen filling stations: Belgium, Canada, China, France, Germany, Greece, Italy, Japan, The Netherlands, Norway, Singapore, South Korea, and Spain.[17] Hydrogen stored at existing filling stations around the world mostly occurs as liquid hydrogen in above-ground tanks.

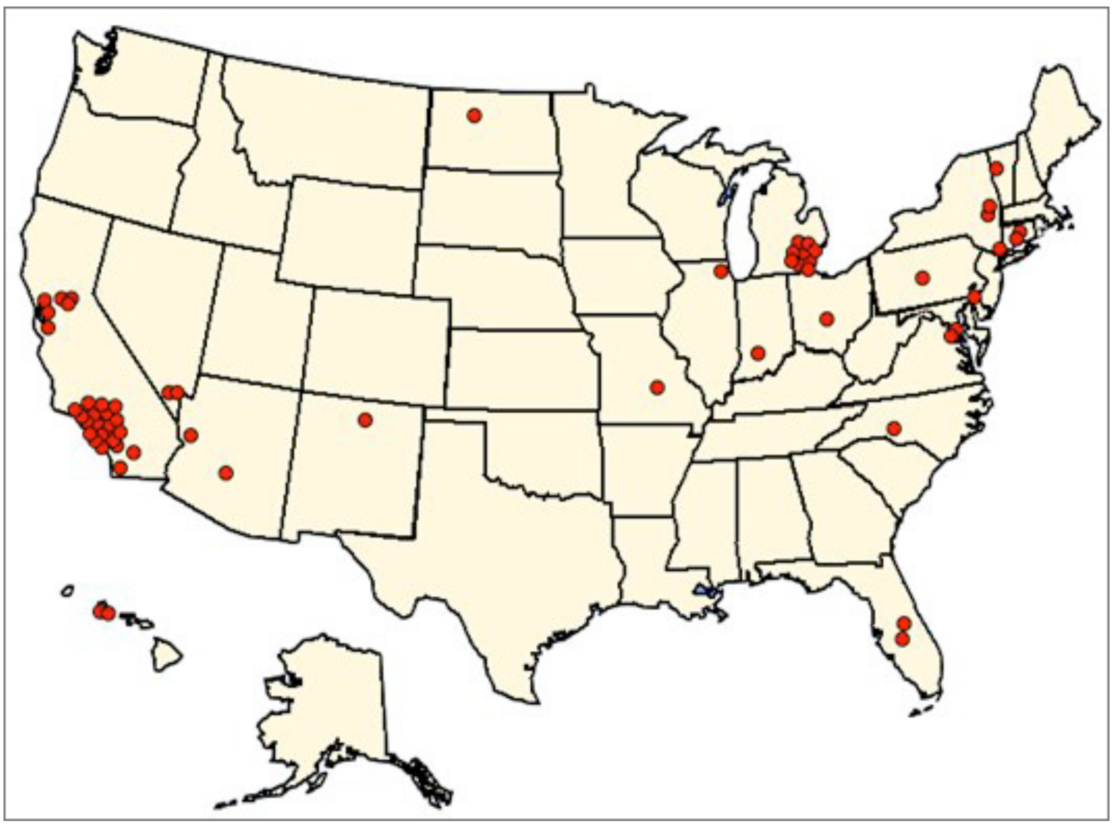

Figure 2.2 This map, as of January 2008 depicts the number and location of operational hydrogen refueling stations with a red dot. Most of these locations exist as demonstration projects. Note the number of those stations in California and those in Michigan, which is nearby the node of the automobile industry in the U.S. [18]

2.3 Overview of Borehole Storage

Borehole storage is a unique approach to underground hydrogen storage that utilizes the well bore as the actual storage apparatus. This research represents the first known attempt where the knowledge and experience of petroleum engineering is applied to underground hydrogen storage. There are many benefits of applying the expertise from the oil and gas industry to this method of hydrogen storage. Lessons learned from tried and tested methods of geologic analysis, drilling, and well completion result in cost savings for hydrogen storage. Metallurgical characteristics of steel, such as corrosivity and material strength, are familiar factors from decades of hydrocarbon exploration and production.

Normally, a well is drilled thousands of feet into the subsurface rock, casing and tubing are run down the length of the hole, and production of oil and/or natural gas commences from underground formations. Here, instead of producing hydrocarbons from deep beneath surface, the bottom of the tubing and casing are capped, and compressed hydrogen gas is stored inside the inner pipe.

Hydrogen storage involves storing compressed H_2 gas in an inner tube, which fits within an outer casing. The clearance between the inner pipe and outer pipe can be on the order of millimeters and centimeters. Hydrogen is stored at a certain pressure within the tube. The amount of pressure tubing and casing are able to accommodate depends upon its wall thickness, alloys used, and heat treatment received during manufacturing. The greater the wall thickness, the greater the pressure a gas can exert on the internal wall of a tube; the smaller the wall thickness, the less force a pipe can withstand from the pressure of the stored gas. Smaller-diameter pipes with thick walls are able to accommodate greater forces exerted by compressed gas than large-diameter and thinly-walled pipes. The appropriate tubing and casing specifications for this research are discussed with the calculations in a subsequent section.

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CHAPTER 3: THE PROJECT

3.1 Project Objective

The objective of this research is to design an underground storage facility at a fueling station that can accommodate a vehicle which fills its 5-kg compressed hydrogen gas tank once a week. The filling station of interest is sized for use of 1,500 kg H_2 per day. The hydrogen needed per vehicle per day is 0.714 kg (5 kg / 7 days). Thus, considering the amount of H_2 inventory and the amount of H_2 used by each vehicle each day, this filling station can accommodate up to 2,100 vehicles per week:

$$\left({(1{,}500\ kg * 7\ days)}\Big/{(1\ day * 5\ kg)} \right) = 2{,}100\ vehicles$$

3.2 Methodologies

Overall, four separate ideas for accomplishing underground hydrogen storage are investigated. One option appears obvious from the onset. This includes storing hydrogen in three separate tubes adjacent to one another within one borehole. Drilling one borehole, as opposed to multiple boreholes, is significantly cheaper. The three tubes are pressurized to 4,000 psi, 8,000 psi, and 12,000 psi. These pressures seem reasonable given the volume of hydrogen required for storage and the ability to fill vehicles with various tank pressures through a cascading technique. The cascading method is explained later.

The second option includes using two boreholes: one borehole with one tube storing hydrogen at 4,000 psi and one borehole with two tubes of hydrogen. The second borehole includes hydrogen compressed to 12,000 psi and 8,000 psi. Unrealistic depths are calculated with these first two approaches. For example, for the single borehole option, the tube at 4,000 psi requires a height of nearly 81,000 ft.

A third approach to storing compressed hydrogen underground at a filling station consists of a single borehole at a constant pressure of 12,000 psi. This scenario involves pumping a dense fluid on the outside of the casing down the length of the borehole and injecting the fluid into the base of the tube. In effect, a reverse piston situation is achieved by applying pressure to the column of gas above the dense fluid. The dense fluid, mercury being the most realistic and appropriate fluid to use, maintains a constant pressure of 12,000 psi on the hydrogen, possibly assisted by a compressor on the ground surface. This fluid must be denser than hydrogen, have no particulates that would create a settling problem at the base of the tube, cannot be too viscous so that it can flow without excessive pumping, is not too expensive, and the fluid should possess well-known properties through past experimentation. Although this storage design entails less drilling costs, it reveals higher pumping and compressor costs than the alternative methods, and includes several technical challenges.

The fourth storage option appears to be the most practical and achievable. Three separate boreholes consist of tubes of hydrogen gas at three separate pressures—4,000, 8,000, and 12,000 psi. Similar to the first and second proposed designs, this design consists of tubes interacting via the cascading method as H_2 discharges into vehicles. A detailed explanation of the calculations and design for this option follows.

3.3 Calculations

An obvious starting point is the ideal gas law. The equation of state of an ideal gas models the approximate behavior of gases under most conditions.

$$PV = nRT$$

P = absolute pressure of the gas (Pa)
V = volume of the gas (m^3)
n = amount of substance (mol)
R = ideal gas constant (m^3Pa/Kmol)
T = temperature (K)

Gas is considered “ideal” under high temperatures and low pressure. However, the ideal-gas state equation produces too much error when modeling the complex behavior of hydrogen under high pressure conditions.

Chen and his colleagues (2009) propose a simplified, but reliable real-gas equation for hydrogen.[1] Their actual-gas state equation accounts for the molecular volume of hydrogen and intermolecular force of hydrogen gas in the ideal gas model. This is accomplished by using a compressibility factor, Z, which is defined as:

$$Z = {}^{Pv}/_{RT}$$

Z = compressibility factor (unit less)
P = absolute pressure of the gas (Pa)
v = specific volume (m^3/kg)
R = ideal gas constant (m^3Pa/Kmol)
T = temperature (K)

The compressibility factor for ideal gas is 1. For hydrogen, Chen et al simplified the above equation to:

$$Z = 1 + {}^{\alpha P}/_{T}$$

α = coefficient, 1.9155×10^{-6} K/Pa

The compressibility factor for hydrogen is greater than that of an ideal gas. However, as temperature in the term $\alpha P/_{T}$ approaches infinity, Z approaches 1.

The ideal-gas equation can now be rewritten to include the compressibility factor, the amount of hydrogen gas required in each storage tube, and the ideal gas constant specific to hydrogen. The specific gas constant accounts for the molecular mass of hydrogen.

$$R_{sp} = {}^{R}/_{M}$$

$$\boldsymbol{PV = ZmRspT}$$

R_{sp} = H_2-specific gas constant (m^3Pa/gK)
M = molecular mass of H_2
m = mass of H_2 required (g)

The height, or depth, required for each borehole must be determined for the design of the storage apparatus. Height is calculated using the total volume within each tube; volume is computed from the above equation. Several parameters, including pressure, down-hole temperature, mass of hydrogen stored in each tube, and internal pipe diameter must be accounted for in the volume calculation.

Pressure

Although each borehole reaches thousands of feet into the subsurface, the pressure throughout the length of the borehole remains unaffected by the atmosphere above. This assumption is reasonable using $0.003\ psi/_{ft}$ as a pressure gradient for gas.

Multiplying the depth of each borehole by the above gas gradient yields insignificant pressure increases for each storage tube. Changes in pressure within each tube result only from incremental pressure reductions from hydrogen discharging into vehicles.

Temperature

Additionally, a temperature at 100 ft (30.48 m) below ground level is assumed throughout the entire height of all three boreholes. This temperature is calculated using a temperature gradient of $^{2.6\ \mathrm{deg\ C}}/_{100\ m}$, which is equal to $^{2.7575\ K}/_{1\ m}$, and assuming an average surface temperature of 23 ^{o}C:

$$(23 + 273) + (30.48 * 2.7575) = 380.05\ K$$

Mass

The mass of hydrogen within the inner tube of each borehole is 1,500 kg. As explained in a subsequent chapter, the usable hydrogen inventory in each tube is actually slightly less than 1,500 kg.

Tubing Diameter

Pipe with larger internal diameters and greater wall thicknesses are used in this project. Conventional tubing used to produce oil and natural gas, which is run inside an outer casing, cannot support the pressures at the volume of hydrogen required. Their internal diameters and wall thicknesses are too small for the high pressures required.

All pipe data is obtained from Grant Prideco's charts of available tubing, casing, and large diameter pipe.[2] The volume and depth of the borehole with 4,000 psi is computed using an inner pipe diameter of 9.625 inches (in), an internal diameter of 9.001 in, a thickness of 0.312 in, an alternate test pressure of 5,700 psi, and internal yield pressure of 6,240 psi, and a collapse pressure of 1,710 psi. These specifics correspond to a pipe grade of P-110. The number 110 in this nomenclature refers to a pipe with 110,000 psi yield strength. For the outer pipe, a grade of C-90 (90,000 psi yield strength) is investigated, with a diameter of 10.75 in, internal diameter of 10.05 in, pipe thickness of 0.35 in, a maximum alternate test pressure is 4,700 psi, internal yield pressure of 5,130 psi, and a collapse pressure of 1,730 psi. Also, the clearance between the inner and outer pipe is 0.2125 in.

The pressure ratings are significant because they must correspond to the desired compression of hydrogen within each borehole. If the pipes become too large, they lose their ability to hold pressurized gas. The pipe data associated with each of the three desired pressures are chosen based on compatibility more so than cost considerations, due to the focus on engineering and design of the storage system.

The maximum alternate test pressure is determined from hydrostatic testing during the pipe manufacturing process. This test evaluates the performance of the pipe by revealing weak areas that cause the pipe to rupture using non-compressible fluids such as oil, drilling mud, water, brine, or diesel.[3] The American Petroleum Institute's Specification for Casing and Tubing (API 5CT) defines alternate test pressure as approximately 80% of the theoretical yield.[4] Pipe cannot experience the entire yield pressure during testing because it compromises the pipe's integrity for use in the field.

The internal yield pressure is the minimum pressure at which permanent plastic deformation of the pipe occurs. Collapse pressure is caused by the differential pressure from the outside to the inside of the tube, and is the minimum pressure at which the steel tube deforms.[5]

Borehole number two, which is pressurized to 8,000 psi, uses an inner pipe with diameter 8.625 in, an internal diameter of 7.625 in, and a pipe thickness of 0.5 in. This pipe grade 100 has an alternate test pressure of 9,300 psi, internal yield pressure of 10,140 psi, and a collapse pressure of 7,980 psi. The outer pipe has a diameter of 9.875 in, internal diameter of 8.815 in, thickness of 0.53 in, an alternate test pressure of 8,600 psi, internal yield pressure of 9,390 psi, and a collapse pressure of 6,630 psi. The grade for this outer pipe is also listed as 100. The inner tube is separated from the outer pipe by 0.095 in.

In the third borehole, the inner pipe has a diameter of 8 in, internal diameter of 6.624 in, thickness of 0.688 in, alternate test pressure of 13,100 psi, internal yield pressure of 14,300 psi, and collapse pressure of 14,930 psi. The outer pipe for this borehole, which is pressurized to 12,000 psi, requires an alternate test pressure of 13,000 psi, internal yield pressure of 14,200 psi, and a collapse pressure of 11,800 psi. Its diameter is 9.625 in, internal diameter 8.375 in, and thickness 0.625 in. The data for the inner pipe corresponds to grade Q-125, and the outer pipe corresponds to grade T-95. The pressure ratings of each outer pipe in all three boreholes are able to withstand the pressure of the stored H_2 gas in case of leak or rupture of the inner storage tube. The container pressurized to 12,000 psi clears the inside of the outer pipe by 0.1875 in. Table 3.1 summarizes the tubing specifics discussed above.

Table 3.1 Pipe diameters and specifics.

	Borehole 1		Borehole 2		Borehole 3	
	Inner Pipe	Outer Pipe	Inner Pipe	Outer Pipe	Inner Pipe	Outer Pipe
Pressure (psi)	4,000		8,000		12,000	
Diameter (in)	9.625	10.75	8.625	9.875	8	9.625
Internal Diameter (in)	9.001	10.05	7.625	8.815	6.624	8.375
Pipe Thickness (in)	0.312	0.35	0.5	0.53	0.688	0.625
Alternate Test Pressure (psi)	5,700	4,700	9,300	8,600	13,100	13,000
Internal Yield Pressure (psi)	6,240	5,130	10,140	9,390	14,300	14,200
Collapse Pressure (psi)	1,710	1,730	7,980	6,630	14,930	11,800
Pipe Grade	P-110	C-90	100	100	T-95	Q-125

3.3.1 Vehicle-by-Vehicle Analysis

Calculating tube volumes and borehole depths require an analysis which accounts for individual vehicles filling their on-board storage containers. A reduction in both H_2 mass and pressure within the boreholes occur as each vehicle fills its tank. The analysis assumes each vehicle fills to its maximum engineered capacity. Also, the underground storage tubes interact in a cascading manner whereby each vehicle's tank is filled to capacity using an automatic switch that withdraws hydrogen from the next highest pressure-rated borehole.

Part of this analysis entails examining different scenarios in which vehicles, with various on-board tank fill capacities, arrive at the station already filled to certain levels of H_2. These constraints impact the total number of vehicles that can fill at the station using the entire hydrogen storage system. Once all vehicles are filled given the parameters in each scenario, the volume and heights required for each storage tube are determined.

The ten experimental scenarios include: (1) vehicles arriving with 0 psi and leaving with a maximum of 7,000 psi; (2) vehicles arriving with a tank pressure of 3,000 psi and leaving filled to 7,000 psi; (3) vehicles arriving with a tank pressure of 5,000 psi and leaving the station with their maximum 7,000 psi; (4) vehicles arriving with 0 psi and leaving with a maximum of 10,000 psi; (5) vehicles arriving at 3,000 psi and leaving at 10,000 psi; (6) vehicles arriving with 5,000 psi and leaving with 10,000 psi; (7) arriving with 7,000 psi and leaving with 10,000 psi; (8) arriving at 9,000 psi and leaving at 10,000 psi; (9) arriving at 0 psi and leaving with a maximum tank capacity of 3,000 psi; (10) and arriving at 2,000 psi and leaving the station filled to a capacity of 3,000 psi. These scenarios are captured in Table 3.2 below. The pressure range of on-board compressed hydrogen gas storage vessels is chosen based upon current norms. The maximum pressure capacity in existing hydrogen ICE and hydrogen fuel cell vehicles commonly fall between 3,000 psi and 10,000 psi. Some of the demonstration projects using fleets of city buses have 10,000 psi storage chambers.

Table 3.2 Ten scenarios used to compute borehole volumes and heights.

Scenario	Vehicle Arrives at Station With Tank Filled to..(psi)	Vehicle Departs Station Filled to Max. Fill Pressure of...(psi)
1	0	7,000
2	3,000	7,000
3	5,000	7,000
4	0	10,000
5	3,000	10,000
6	5,000	10,000
7	7,000	10,000
8	9,000	10,000
9	0	3,000
10	2,000	3,000

3.3.2 Example Calculation

Consider the scenario in which a vehicle arrives at the H_2 filling station with a completely empty tank, and departs the station filled to its maximum tank capacity of 3,000 psi (scenario # 9 from above). The quantity of hydrogen already in the vehicle's tank upon arrival is 0 kg. Therefore, the quantity of H_2 required to fill the vehicle to maximum capacity is:

$$5{,}000\ g - 0\ g = 5{,}000\ g.$$

The quantity of H_2 discharged from each borehole into each vehicle can be broken down for this example in the following manner: Borehole 1 = 2,000 g; Borehole 2 = 2,000 g; Borehole 3 = 1,000 g. This distribution must equal 5 kg—the maximum amount of H_2 each vehicle can accommodate.

To begin, the total volume (V_t) is calculated for each tube. These values remain constant for each of the three boreholes for all ten scenarios. In this example calculation, only tube one is examined. Although tube one is assigned a pressure rating of 4,000 psi, a more practical starting pressure (P_n) for the tube is 3,950 psi (27,231,300 Pa) because filling the tube to exactly 4,000 psi is nearly impossible. The starting pressure (P_n) occurs where n=0 because no vehicles have arrived at the station. Also, recall that the total quantity of H_2 in each tube is 1,500,000 grams. To calculate V_t, the equation $PV = ZmRspT$ is re-arranged to:

$$Vt = {ZmRspT}/{Pn} = {\left(1 + {\alpha Pn}/{T}\right) mRspT}/{Pn}$$

V_t = total volume of tube with all 1,500 kg H_2 (m^3)
α = 1.9155x10^{-6} K/Pa
P_n = starting pressure within borehole at n^{th} vehicle (Pa)
T = temperature (K)
m = mass of H_2 required (g)
R_{sp} = H_2-specific gas constant (m^3Pa/gK)

$$Vt = \left(1 + {(0.0000019155 * 27{,}231{,}300)}/{380}\right) * 1{,}500{,}000 * 4.124 * 380 \Big/ 27{,}231{,}300$$

$$Vt = 98.189\ m3$$

Next, the incremental volume reduction in each borehole from each vehicle's withdraw is determined. The incremental volume reduction caused in tube one by the amount of H_2 withdrawn from the 1st vehicle pulling up to station is:

$$V = {\left(1 + {\alpha Pn}/{T}\right) mRspT}/{Pn}$$

$$V = \left(1 + {(0.0000019155 * 27{,}231{,}300)}/{380}\right) * 2{,}000 * 4.124 * 380 \Big/ 27{,}231{,}300$$

$$V = 0.13092\ m3$$

Likewise, the volume associated with the mass withdrawn in tube one by the 8th vehicle at the station is calculated by using the pressure following the departure of the 7th vehicle:

$$= \left(1 + {(0.0000019155 * 26{,}975{,}897)}/{380}\right) * 2{,}000 * 4.124 * 380 \Big/ 26{,}975{,}897$$

$$V = 0.13201\ m3$$

The incremental pressure reduction in each borehole from each vehicle's withdraw is then determined:

$$P = {(1 + {\alpha Pn}/{T})mRspT}\Big/{(Vt - Vx) - Vn}$$

V_x = sum of incremental volumes withdrawn from all vehicles prior to n^{th} vehicle (m^3)
V_n = incremental volume of n^{th} vehicle (m^3)

In this example calculation, the incremental pressure reduction in tube one by the amount of H_2 withdrawn from the 1st vehicle at the station is:

$$\left(1 + {(0.0000019155 * 27{,}231{,}300)}/{380}\right) * 2{,}000 * 4.124 * 380 \Big/ (98.2 - 0.13092) - 0$$

$$P = 36{,}357\ Pa$$

Likewise, the incremental pressure reduction caused in tube one by the amount of H_2 withdrawn from the 8th vehicle pulling up to station is:

$$\left(1 + {(0.0000019155 * 26{,}975{,}897)}/{380}\right) * 2{,}000 * 4.124 * 380 \Big/ (98.2 - 0.91968) - 0.13201$$

$$P = 36{,}660\ Pa$$

This incremental change in pressure is subtracted from the total pressure within the tube prior to the arrival of the 8th vehicle. The resultant pressure is the new starting pressure (P_n) in the tube when the nth (in this case, the 9th) vehicle arrives at the station.

Vehicles continue to withdraw H_2 from tube one until the pressure in the tube is equal to or less than the tank pressure of the nth vehicle. At this point, H_2 will be discharged from the next highest pressure-rated tube. If the pressure in tube two is equal to or less than the tank pressure of the nth vehicle, then H_2 will be discharged from tube three. If the pressure in tube three is equal to or less than the tank pressure of the nth vehicle, then vehicle n cannot continue to fill its tank.

For example, when the pressure within tube one becomes incapable of sustaining adequate flow rates to provide vehicle number 391 with any significant amount of hydrogen, the next vehicle (392nd), begins withdrawing 3,000 g of hydrogen from tube two and 2,000 g from tube three. Vehicle number 401 can only withdraw hydrogen from the third, and last, tube. Vehicles 401-485 are withdrawing all 5,000 g of hydrogen from tube three. Therefore, the overall storage system in this scenario can accommodate 485 vehicles before the filling station must resupply its hydrogen gas inventory.

The total volume required in each tube is computed by adding the incremental volumes from each vehicle's withdraw. These total volumes are used to calculate the height (i.e. depth) of each tube (i.e. borehole).

In this example, the height required of tube one is:

$$V = \pi r^2 H$$

$$H = V/\pi\left(\frac{\frac{ID}{12}}{2}\right)^2$$

ID = Internal diameter of pipe

V = 95.4 m^3 = 3,369.1 ft^3

$$H = \frac{3{,}369.1}{\pi\left(\frac{\frac{9.001}{12}}{2}\right)^2} = 7{,}624\ ft$$

This process is continued for all ten scenarios for each storage tube.

For scenarios that consist of vehicles arriving at the station with some initial mass and pressure in their on-board tanks, a 1:1 ratio of mass:pressure is assumed to compute the H_2 mass needed to fill each vehicle. As stated above, this amount is then distributed among each of the three tubes such that the total withdrawn from all tubes equals the total mass required by each vehicle (5 kg).

For example, the scenario in which vehicles arrive at the station with 7,000 psi of H_2 and depart the station filled to their maximum tank capacity of 10,000 psi, the mass required by each vehicle is determined by:

$$\frac{7{,}000\ psi}{10{,}000\ psi} = \frac{X\ g}{5{,}000\ g} = 3{,}518\ g$$

$$5{,}000\ g - 3{,}518\ g = 1{,}482\ g$$

Thus, 1,482 g is required to fill each vehicle's tank to capacity. This quantity is distributed to the three tubes such that the sum is equal to 1,482 g.

Scenarios that involve vehicles arriving at the station with some quantity of H_2 in their tanks (i.e. example immediately above) are not the limiting factor in calculating required borehole depths. The depths calculated in these scenarios are ignored because they are significantly less than those scenarios that include vehicles arriving at the station with completely empty tanks. The 'empty tank' scenarios (i.e.: 1, 4, 9) result in the greatest depths. Therefore, it is necessary to vary the initial mass of hydrogen assigned to each of the three tubes H_2 (summing to each vehicle's tank capacity) in order to determine if the prior calculated depths increase. Borehole depths obtained by varying the mass distributed to each tube in scenarios 1, 4, and 9 are shown in Table 3.3.

Table 3.3 Borehole depths in scenarios 1, 4, and 9 when varying H_2 mass distributed to each tube for vehicle fill.

		Depth (ft)		
Case	Mass in Tubes 1,2,3 (g)	Borehole 1	Borehole 2	Borehole 3
A	2,000 2,000 1,000	7,624	5,782	5,614
B	1,000 2,000 2,000	7,676	5,782	5,660
C	2,000 1,000 2,000	7,624	5,726	5,660
D	0 100 4,900	0	5,859	5,895
E	4,900 0 100	7,293	0	5,859
F	100 4,900 0	7,781	5,821	0
G	1,666 1,667 1,667	7,553	5,715	5,727
H	1,000 3,000 1,000	7,676	5,852	5,811
I	3,000 1,000 1,000	7,392	5,893	5,811
J	1,000 1,000 3,000	7,676	5,893	5,640
K	5,000 0 0	7,351	0	0
L	0 5,000 0	0	5,815	0
M	0 0 5,000	0	0	5,671

The largest value in each borehole column represents the deepest each borehole must extend into the subsurface. Cases D, E, F, K, L, and M are extreme cases, in terms of the mass withdrawn from each borehole. Each case ultimately affects the required depths of each borehole. As seen from the table, borehole one must be approximately 7,780 ft (determined from Case F), borehole two must be 5,893 ft (from Cases I and J), and borehole three must be 5,895 ft deep (from case D).

3.4 Results

For the borehole with hydrogen pressurized to 4,000 psi, the volume required in the inner tube is approximately 3,438 ft^3, and it has a height of 7,781 ft. The hydrogen storage tank pressurized to 8,000 psi has a volume of 1,869 ft^3, and a height of 5,893 ft. Borehole three has a volume of 1,411 ft^3, a height of 5,895 ft. Table 3.4 captures the final—revised—borehole depths for each scenario. The table also shows the total number of vehicles able to fill at the fueling station in each scenario, depleting the station's entire hydrogen inventory.

Table 3.4 Summary of results.

Scenario	Final Borehole Depths (ft)			Total # Vehicles Served at Fueling Station, Depleting Inventory
1	**7,781**	**5,893**	**5,895**	**485**
2	1,889	3,792	4,456	626
3		2,261	3,463	813
4	**7,781**	**5,893**	**5,895**	**485**
5	1,883	3,786	4,457	509
6		2,269	3,462	459
7		730	2,471	468
8			1,470	704
9	**7,781**	**5,893**	**5,895**	**485**
10	3,872	4,762	4,969	1,339

3.5 Design & Technical Functionality

The underground hydrogen storage system proposed for a filling station is designed for functionality and safety. Customers ought to fill their vehicles with operational ease and without hazard. The system should also be user-friendly for the station clerk and for the delivery apparatus—pipeline and/or tube trailer. One feature that would greatly reduce cost of hydrogen delivery, and which exists at most of the experimental filling stations throughout the U.S., is an on-site electrolyzer or micro steam methane reformer. This local hydrogen production can augment the supply of delivered hydrogen. Figure 3.1 is a map view illustrating the spatial arrangement of the compressed hydrogen gas dispenser, compressor, manifold, and transfer point. A fenced area of approximately 22 ft by 60 ft surrounds the significant hydrogen systems, and offers space for a concrete slab adjacent to the transfer point for tube trailer deliveries. The tube trailer backs in or pulls straight through, depending on the land availability and layout of the filling station.

H_2 from the trailer is discharged into a high-pressure 'receiver' pipe, which is connected to the compressor inside the overhead structure.

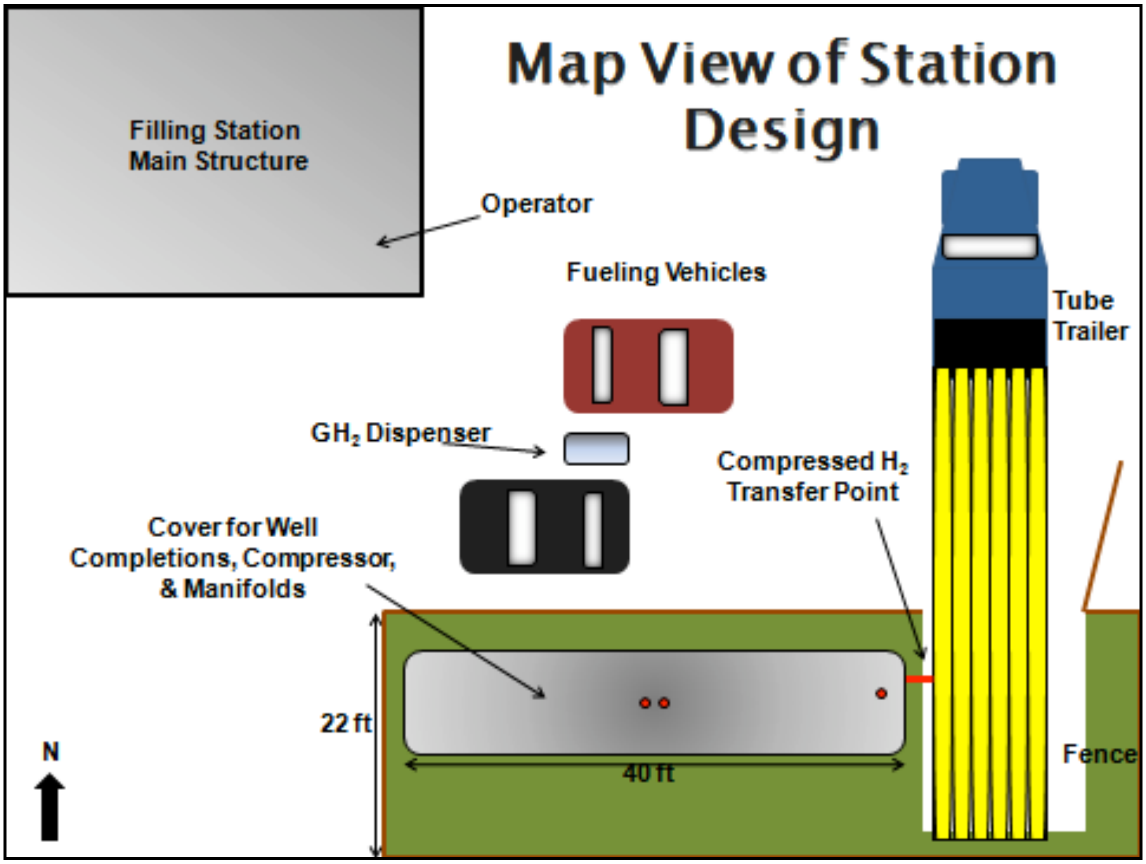

Figure 3.1 Map view of proposed hydrogen fueling station.

Although the well completions, compressor, gauges, and regulations systems are to be accessible from ground surface, it is encouraged that a fire-resistance cover be constructed over this equipment. This serves to protect the equipment from precipitation, reduce noise for customers and neighbors, minimize the effects of extreme ambient air temperatures on the compressor, and safeguard against access to unauthorized personnel. The space underneath this cover is large enough—40 ft long by 10 ft wide—to accommodate an additional high pressure hydrogen compressor in the event that the filling station owner/operator wishes to have redundancy. The overhead structure is equipped with multiple ventilation tubes extending high enough into the air to avoid human exposure. Positioned in the center of the domed roof and near the transfer point, a location susceptible to gas leaks, these tubes allow H_2 to escape this enclosed space, avoiding a possible volatile situation.

Drivers are able to fill their vehicles at the H_2 dispenser by pulling straight through. Due to regulations dictating minimum safe distances of hydrogen systems from certain exposures, the H_2 dispenser is to be at least 35 ft from lot lines.[6] The station operator is able to observe not only dispensing operations, but also hydrogen delivery operations at the tube trailer. Customers have access to a manual emergency shutdown device within feet of the dispenser, and the station operator can override the automatic safety features of the system in case of an emergency from within the station. Figure 3.2 is a profile view of the H_2 storage system when looking from north to south.

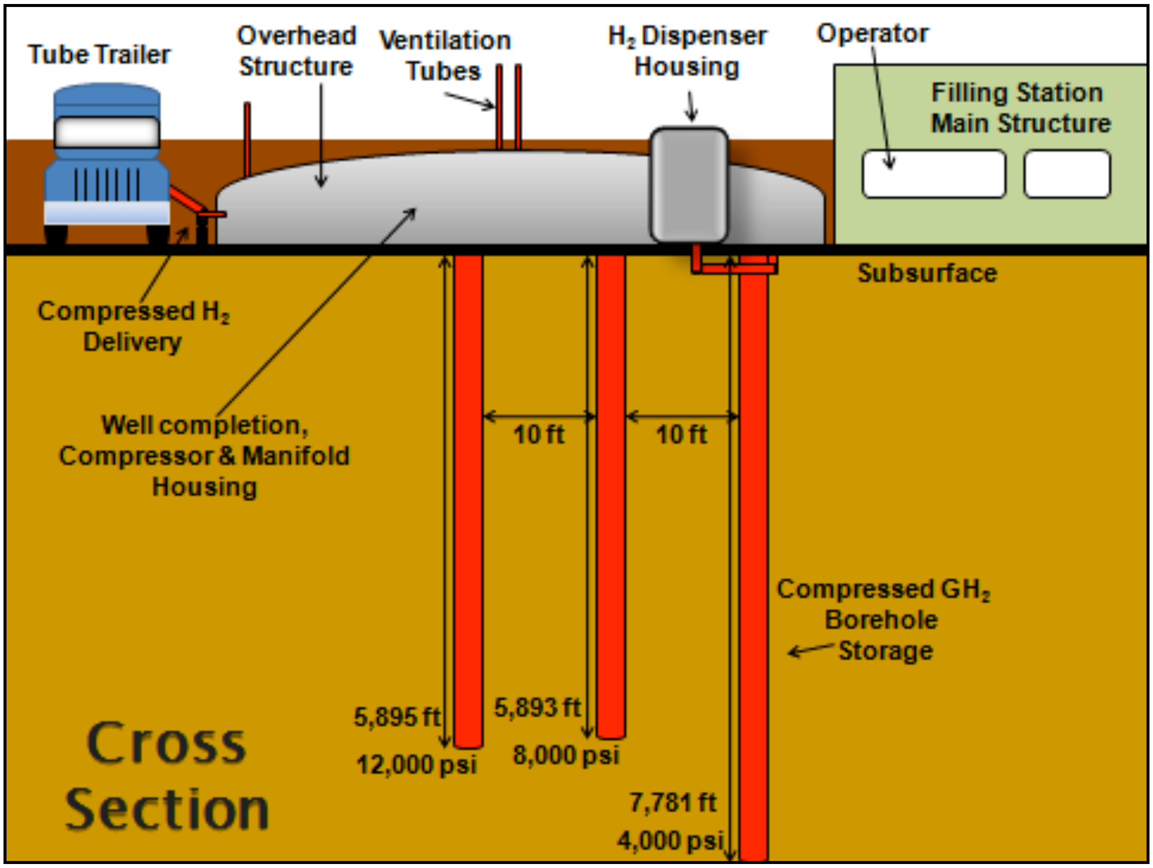

Figure 3.2 Profile view of H_2 filling station & underground borehole storage apparatus.

Three boreholes extend vertically beneath the filling station. Each well is completed separately at the surface. The boreholes are drilled in a linear fashion 10 ft apart from one another. The center well is to be drilled first. To ensure the boreholes do not intersect at any point while drilled to their assigned depths, the drilling contractors are told to drill the two outside wells at a 2-degree angle, with a deviation from that original angle of no more than 2 degrees. Directional drilling accounts for the tendency of drilling pipe to drift as a result of various rock types and anomalies encountered in the subsurface. Figure 3.3 is a more detailed profile view of the hydrogen equipment underneath the protective structure.

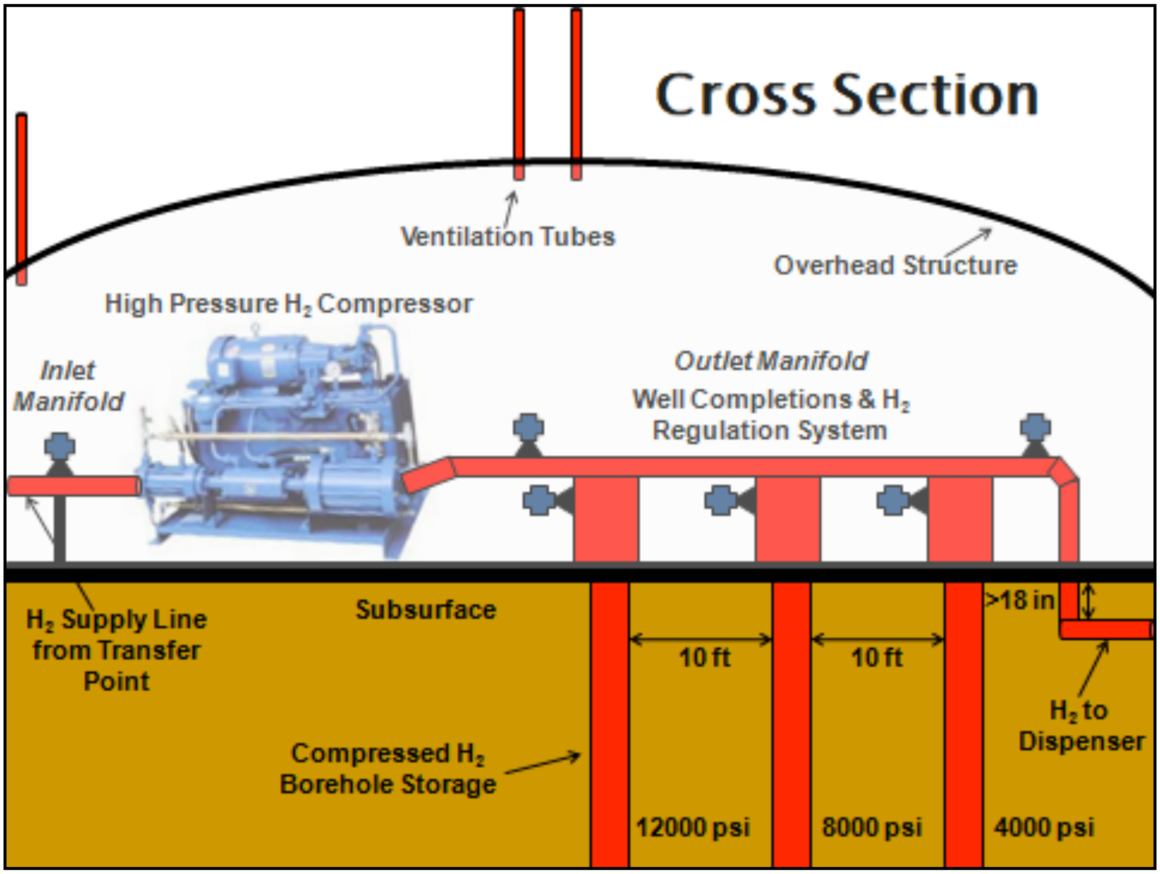

Figure 3.3 Profile view of compressor and manifold housing.

The H_2 flows from the tube trailer, through the transfer point, and into the compressor. The high-pressure hydrogen gas compressor used for this design is one of the LX Series™ units offered by Hydro-Pac, Incorporated.[7] This is a single-stage compressor with an electric motor and a hydraulic oil pump. The compressor discharges H_2 at 12,000 psi, and has an inlet pressure range of 1,500 to 6,000 psi.[8] This inlet pressure range is suitable for the delivery of compressed H_2, which is typically pressurized between 2,400 psi to 3,600 psi in tube trailers. Therefore, no charge pump is necessary to elevate the pressure of H_2 flowing from the tube trailer into the compressor. The inlet manifold, which appears to the left of the compressor in Figure 3.3, is equipped with a regulation device, a backflow prevention device, and a pressure gauge.

The outlet manifold connecting the well heads of the three separate boreholes is also equipped with pressure gauges, pressure regulators/valves, and emergency shutdown devices. Compressed hydrogen gas flows from one of the storage chambers to the dispenser housing, a distance of less than 25 ft. The storage bank from which H_2 flows depends on the capacity of the vehicle tank being filled and on the remaining inventory throughout the storage system. The tube through which H_2 flows to the dispenser lies within an outer pipe, and they are buried horizontally in the subsurface. The diameter, thickness, and pressure ratings of the pipes used to connect the tanks to the dispenser housing resemble those used for the 12,000 psi storage bank. The pipe must be emplaced at least 18 inches below ground surface to ensure that it clears all underground utility obstructions. Once underneath the H_2 dispenser/pump, the pipe turns vertically, penetrates through the surface, and enters the pump housing.

3.5.1 Operations at the Pump

The three-stage cascade pressure arrangement is the process by which drivers fill their vehicle with hydrogen at the pump. The dispensing operation described below mimics the one described by Karner, McCamman, and Francfort in their technical prototype report completed in 2005 as part of the U.S. Department of Energy's Advanced Vehicle Testing Activity.[9]

Operation of the dispensing system begins with the driver interfacing with the display screen at the pump. The display screen shows price per gasoline gallon equivalent (gge), provides real-time dispensing status, and displays the amount of fuel pumped and cost of transaction. After driving up to the pump, the driver swipes his/her credit card to initiate fueling. At this point, the dispenser controller receives an 'enable' signal from the pump interface to begin fueling. Simultaneously, the control unit relieves pressure in the output header within the pump housing by opening a high pressure vent.

These ventilation pipes extend high into the air at both the pump housing and in the compressor/manifold housing. In overpressure conditions, these vents release excess hydrogen into the atmosphere without the danger of human interaction. When hydrogen reaches the exit of the vent stacks, it burns on contact with outside air, producing only water as its waste. To avoid premature ignition of the hydrogen in the vent stack prior to reaching the exit due to high temperatures, a temperature monitor is installed in the vent stack to trip a helium injection system.[10] As an inert gas, helium is useful in subduing the volatility of hydrogen. Although existing at the dispenser housing, it is not essential that the ventilation tubes penetrating the metallic structure be equipped with this temperature monitoring device.

Next, a small puff of gas is delivered into the vehicle's compressed hydrogen gas tank to verify the vehicle's tank pressure. The control unit uses this data and a measurement of the ambient air temperature to compute the initial fill pressure and a temperature-compensated final fill pressure. This maximizes the amount of hydrogen fuel delivered to the vehicle. A ‘fill request’ is then sent to the fuel supply plant controller and filling commences.

The dispenser “modulates the flow control valves to produce smooth and efficient fuel delivery” during filling.[11] If the flow rate falls below a programmable initial rate, the dispenser will request from the supply plant controller to open valves to initiate flow from the next highest pressure zone (i.e. 8,000 or 12,000 psi). During the time it takes to process this request, a proper flow rate must be maintained. This is accomplished by the dispenser modulating the flow control valves to increase the input pressure immediately prior to the transition. “If a higher-pressure zone is not available, the dispenser controller will allow flow to continue until a programmable minimum flow is reached or the temperature-compensated fill pressure has been met.”[12]

When the maximum temperature-compensated fill pressure is reached, the fill is considered complete. The dispenser sends a signal to the fuel supply plant to close valves. Lastly, the driver observes on the display screen the final data from the fueling operation.

3.5.2 Safety Measures

Dispensing hydrogen fuel is, essentially, a hazard-free process due to the many safety features involved. In case of an emergency, all gas supply valves close. This occurs manually by activating an emergency shutdown switch nearby the pump, as well as automatically through the monitoring system within the dispenser controller. Other features include detection of air and hydrogen mixing in the dispenser, excessive flow, flames, combustible gases, over-pressure, hydrogen leaks, loss of control power, excess fill time, and detection of large temperature differentials between dispensed hydrogen, gas in the vehicle tank, and of the ambient air.[13] Additionally, as explained in a subsequent chapter, several building codes and technical standards have been developed to ensure safe construction and operation of compressed H_2 systems. Adherence to these codes and standards minimizes the hazards associated with underground hydrogen storage, operations at the pump, and exposure to all ancillary hydrogen systems.

3.6 References

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12. Ibid.
13. Ibid.

CHAPTER 4: PROJECT COSTS

Technologies seldom emerge from the developmental stage without robust financial assessments backing their success in the real world. Many unknowns and several costs are associated with borehole hydrogen storage described herein. However, these cost considerations become less significant with the emergence of a hydrogen economy, as competition dampens the overall capital and operating expenditures associated with underground H_2 storage ventures.

4.1 Steel Pipe Costs

Underground compressed hydrogen gas storage requires more capital than operating expenses. Pipe grades and connections necessary to withstand highly compressed gas and temperature differentials are costly. As shown in the calculations above, the deepest borehole requires one outer tube and one inner tube stretching7,781 ft into the subsurface. If each pipe length is 44 ft, this deepest borehole would require 177 pipe sections fitted together.[1]

The cost of pipe depends on its weight because weight is a function of thickness and grade. Thicker pipes weigh more by the foot than pipes with thinner walls. The grading system is a standardized method of specifying the strengths of pipe used in wellbores. Casing and tubing used in the oil and gas field are typically made of steel, but their grades differ by the alloys used and the type of heat treatment received during manufacturing.

Grades are typically designated by a letter and a number. The letter refers to the tensile strength and the second part of the nomenclature refers to the minimum yield strength (88% of theoretical yield) of the metal after heat treatment.[2] The highest quality pipe grade used in the storage design, obtained from Grant Prideco's pipe tables, is Q125. The letter "Q" signifies that this steel was quenched and tempered during fabrication, and "125" denotes yield strength of 125,000 psi. This grade steel costs $60.13/ft.[3] The remaining pipe grades used, in decreasing quality, include P110, 100, T95 and C90. Grade C90 costs $41.51/ft. Costs associated with all pipes used in this project are listed in Table 4.1 below.

Prices quoted in the table include plain-end thread/weld pipe. A premium connection charge of $1,000 per connection is applied to ensure a gas-tight seal. This charge is added for connections on both the inner and outer pipe. Truck delivery costs depend on the distance from the distribution point and the tonnage. Truck delivery costs represented in the table below are calculated based on several assumptions and current practices expressed by a sales representative from Vallourec & Mannesmann (V&M) Tubes.

Table 4.1 Total pipe costs

	Borehole 1		Borehole 2		Borehole 3	
	Inner Pipe	Outer Pipe	Inner Pipe	Outer Pipe	Inner Pipe	Outer Pipe
Borehole Depth (ft)	7,781		5,893		5,895	
Pipe grade	P-110	C-90	100	100	T-95	Q-125
Pipe cost per foot ($) *	28.74	41.51	76.00	92.00	72.88	60.13
Pipes required	177	177	134	134	134	134
Pipe cost ($)	5,082	7,341	10,179	12,322	9,764	8,056
Premium connection charge ($) *	174,841	174,841	131,932	131,932	131,977	131,977
Pipe delivery costs ($) *	1,776	1,776	1,345	1,345	1,346	1,346
Total costs per pipe ($)	181,699	183,958	143,456	145,599	143,087	141,379
Total costs per borehole ($)	365,657		289,054		284,466	
Total pipe costs ($)	**939,178**					

*Price quotes and assumptions are based on a conversation with a Vallourec & Mannesmann (V&M) Tubes sales representative on April 9, 2010. Assumptions: (1) Each pipe section length is 44 ft; (2) premium connection charge is $1,000 each; (3) average cost of pipe section per ton is $1,900; (4) weight of pipe per foot is 30 lbs; (5) tons of pipe per truck load is 23 tons; and (6) pipe delivery cost estimates are valid for delivery to well sites within a 50 mile radius of the V&M distribution center in Houston, Texas. Delivery costs increase substantially outside the 50-mile radius, and vary by distance traveled.

4.2 Drilling and Completion Costs

Drilling and completion (D&C) costs represent another expenditure necessary for the proposed underground hydrogen storage method. D&C costs include the cost of physically drilling a hole in the ground to the specified depth, running casing, hanging tubing, and installing down-hole equipment and procedures, such as chokes, packers, and, in this case, plugging the bottom of the tubes. It also includes completion costs when completing the well on the ground surface.

The annual Joint Association Survey (JAS) on Well Drilling Costs publication documents estimated drilling costs for onshore and offshore sites, listed according to depth and area/U.S. state. In 1981, Lewin & Associates, Inc., a financial services firm, authored

"Economics of Enhanced Oil Recovery," in which they developed a regression based on the costs outlined by JAS.[4] Lewin & Associates' cost regressions are modeled by:

$$C = a_1 e^{a2d}$$

The coefficients a_1 and a_2 are based off of region, and d is borehole depth in feet.

In his PhD dissertation, titled "The Economics of CO_2 Transport by Pipeline and Storage in Saline Aquifers and Oil Reservoirs," Sean McCoy uses Lewin & Associates' work, in combination with the EIA Oil and Gas Lease Equipment and Operating Cost index, to compute D&C costs. Updating the a_1 parameter values to today's dollars, and using Lewin & Associates' equation above, D&C costs for the underground hydrogen storage design can be computed. Table 4.2 is extracted from McCoy's research in which he updated parameter a_1 to 2004 U.S. dollars.

Table 4.2. Regression coefficients for calculating well D&C costs (for 2004)

Region	States	a_1 (2004 US$)	a_2
1	AK		
2	CA, OR, WA	70,123	0.00032
2A	Pacific Coast-Offshore, ID, NV, UT	185,819	0.00032
3	CO, AZ, NM-West	80,086	0.00027
4	WY, MT, ND, SD	74,808	0.00028
5	TX-West, NM-East	43,986	0.00034
6	TX-East, AR, LA, MS, AL	44,041	0.00035
6A	Gulf Coast-Offshore	996,487	0.00011
7	OK, KS, NE, MO, IA, MN	42,493	0.00035
8	MI, WI	65,370	0.00038
9	IL, IN, KY, TN	34,362	0.00039
10	OH, PA, WV, NY, VA, NC	23,529	0.00051
11	SC, GA, FL	216,124	0.0003

Assuming an annual inflation rate of 1.7%, the parameter value of a_1 is updated from 2004 to 2010 dollars. The total D&C costs are calculated for each hydrogen storage project in the various regions. Borehole 1 corresponds to a depth of 7,781 ft with a H_2 storage pipe pressurized to 4,000 psi; borehole 2 has a depth of 5,893 ft with a tube pressurized to 8,000 psi; borehole 3 has a depth of 5,895 ft with a tube pressurized to 12,000 psi. Table 4.3 estimates the total D&C costs of H_2 storage projects at filling stations in the various regions and states listed. Although not applicable to the hydrogen storage design, offshore D&C costs are, predictably, the highest. The remaining ten onshore regions average approximately $2,152,000 per project for D&C costs.

Table 4.3 Regression coefficients for calculating well D&C costs (updated for 2010) and total D&C costs for borehole H_2 storage by region

Region	States	a_1 (2010 USD)	a_2	Well 1 Cost (USD)	Well 2 Cost (USD)	Well 3 Cost (USD)	Total Cost (USD)
1	AK						
2	CA, OR, WA	77,587	0.00032	935,717	511,401	511,728	1,958,846
2A	Pacific Coast-Offshore, ID, NV, UT	205,597	0.00032	2,479,558	1,355,161	1,356,029	5,190,749
3	CO, AZ, NM-West	88,610	0.00027	724,233	435,003	435,238	1,594,475
4	WY, MT, ND, SD	82,770	0.00028	731,244	431,000	431,241	1,593,485
5	TX-West, NM-East	48,668	0.00034	685,778	360,912	361,157	1,407,848
6	TX-East, AR, LA, MS, AL	48,728	0.00035	742,196	383,298	383,567	**1,509,061**
6A	Gulf Coast-Offshore	1,102,548	0.00011	2,594,862	2,108,240	2,108,704	6,811,807
7	OK, KS, NE, MO, IA, MN	47,016	0.00035	716,109	369,826	370,085	1,456,019
8	MI, WI	72,328	0.00038	1,391,289	678,949	679,465	2,749,704
9	IL, IN, KY, TN	38,019	0.00039	790,515	378,556	378,851	1,547,922
10	OH, PA, WV, NY, VA, NC	26,033	0.00051	1,377,033	525,740	526,276	2,429,049
11	SC, GA, FL	239,127	0.0003	2,468,325	1,400,935	1,401,776	5,271,035

Variations in D&C costs for oil and gas ventures throughout the U.S. are analogous to D&C costs for projects associated with H_2 borehole storage. Despite the purpose for drilling a well, factors that affect the prices of goods, services, and transportation remain fairly constant and predictable throughout a particular region. Such factors include regional demand, distance to population centers, price of gasoline, weather, availability of supplies, regulations that must be adhered to when drilling wells, state fees and taxes, and the geologic nature of the subsurface. Some regions have rock that is much more difficult to drill through than other areas, affecting drilling time. For example, southeast Texas and Louisiana boast sandy rock, which decreases drilling time and overall D&C costs.

4.3 Compressor Cost

Specialized equipment, including heavy duty hydrogen gas compressors, manifold and pressure regulation systems, valves, dispensers, gas detection sensors and alarms, and the customer interface display at the pump represent additional capital costs. The use of specialized equipment necessary for hydrogen storage and dispensing operations are mandated by current regulatory bodies. These codes and standards are discussed in a subsequent section.

Large compressors must be able to compress hydrogen gas to 4,000, 8,000, and 12,000 psi on a regular basis and operate in a variety of ambient air temperatures. In order to obtain realistic cost data associated with heavy duty hydrogen compressor, a price quotation was acquired from Hydro-Pac, Inc.[5] Hydro-Pac has several decades' worth of experience in manufacturing high-pressure pumps, compressors, and equipment.

A quote was requested for their compressor model C12-40-10500LX/SS-H_2. This compressor unit costs $79,620, with an option to add an aftercooler, which costs $1,200. An aftercooler cools the H_2 discharge from the compressor to approximately 150-200 ^oF.

Cooling the H_2 discharge is not essential for this storage project, but modest reductions in gas temperature may help maximize the amount stored in each cylinder.

An estimated total cost for the borehole H_2 storage design is shown in Table 4.4. This total does not include the actual hydrogen dispenser and related equipment at the pump, the electricity and fuel-related expenses required to maintain operation of the compressor, and the structure used to cover the well completions and compressor. However, this total cost does include everything from the point of transfer (tube trailer delivery connection) to the underground pipe supplying hydrogen to the dispenser. D&C costs are specified for the region of eastern Texas, Arkansas, Louisiana, Mississippi, and Alabama. The compressor cost includes the price ($1,200) of the after cooler. Miscellaneous costs include those relating to specialized equipment necessary for the borehole hydrogen storage design, including valves, gauges, regulators, additional high-pressure tubes and hoses, sensors, leak detectors, backflow prevention devices, and electrical equipment. The miscellaneous category represents expenses with the most uncertainty.

Table 4.4 Total D&C, steel pipe, compressor, and miscellaneous costs associated with borehole compressed hydrogen gas storage at a filling station

	Cost (USD)
Drilling & Completion	1,509,061
Steel Pipe	939,178
Compressor	80,820
Miscellaneous	50,000
Total	**2,579,059**

4.4 Operation & Maintenance Expenses

Operation and maintenance (O&M) costs for filling stations using the borehole hydrogen storage technique are much less significant than the initial capital costs required. However, these expenses must be considered. Replacing and maintaining specialized equipment used in this design, such as the compressor, pressure valves, high-strength tubing, hoses, and fittings, fire monitors and alarms, leak detectors, and the computer used at the pump is costly. As mandated by several codes, each filling station owner must hire a certified corrosion specialist and certified engineer to maintain and inspect the equipment on an annual basis. The cost of overhead, employee salaries, electricity required for the heavy-duty hydrogen compressor, and the cost of hydrogen delivered to the station represent additional O&M costs.

4.5 References

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CHAPTER 5: THE CHALLENGES

5.1 Technical Factors

Impediments to developing and implementing underground borehole hydrogen storage at filling stations relate to existing technical challenges, current economics, and public acceptance. The underground hydrogen storage apparatus for filling stations proposed herein reveals several technical challenges, including hydrogen embrittlement in steel and pipeline transmission. Funding allocated to research and to develop solutions to these technological issues in both the public and private sectors will increase as demand for hydrogen fuel cell vehicles increases.

5.1.1 Hydrogen Embrittlement

Embrittlement of metals is a risk that must be addressed for the long term success of underground borehole storage, and indeed, for the entire hydrogen economy. Many decades' worth of materials engineering research has been applied to understanding the phenomenon of hydrogen embrittlement. Pipes subjected to extended exposure to hydrogen brittle over time, aiding in the reduction of their load-bearing capacity. Hydrogen embrittlement depends on variables such as temperature, pressure, type and concentration of impurities in the metal, physical and mechanical properties of materials used, hydrogen diffusion rate, surface conditions, and magnitude and type of stresses.[1] Figure 5.1 shows an example of how hydrogen atoms present in steel affects the integrity of the metal.

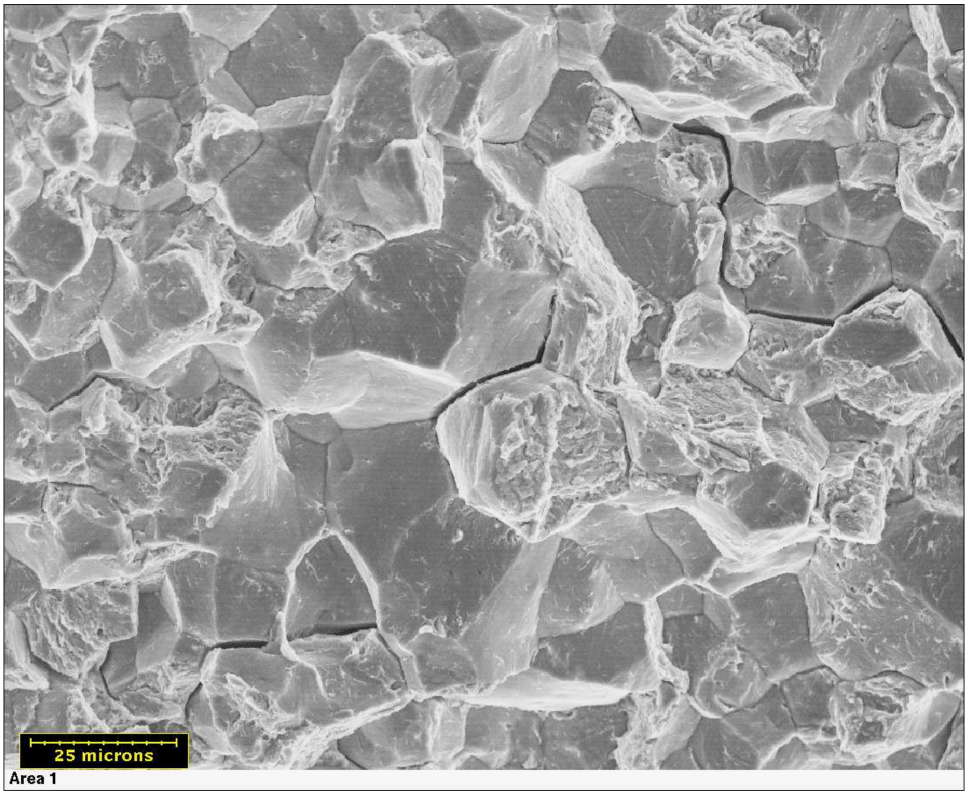

Figure 5.1 Hydrogen embrittlement in a portion of a zinc-plated carbon steel. Over-pressurization externally or internally induces cracking in the steel and the crack propagates over time.[2]

Hydrogen induced cracking (HIC), commonly referred to as hydrogen embrittlement, results from the introduction of hydrogen into the bulk material externally, or from hydrogen which already resides in the metal from the forming and/or finishing processes. Only atomic hydrogen can diffuse through the metallic latticework because of the size of a hydrogen molecule. After dissociating from a hydrogen molecule, the hydrogen atom adsorbs to the surface of the metal. It then migrates along this surface until it reaches a region of locally increased solubility. Atomic hydrogen diffuses through the microstructure, destined for locations where it can combine with other hydrogen atoms to form hydrogen molecules, such as grain boundaries, voids, dislocations, or defects in the crystalline structure.[3] These hydrogen molecules exert pressure within the microstructure, inducing cracks and failures in the metal. External and internal stresses cause these cracks to propagate to the surface or along the surface of the metal.

Diffusion is driven by a gradient in the electric field, temperature, and/or chemical potential, which results from differences in hydrogen concentration between the metal lattice and the environment.[4] For example, it has been found that at temperatures below 200 ^{o}C, sites in the metal matrix, known as traps, capture and delay migrating hydrogen atoms.[5] Increases in temperatures decrease this trapping energy. Moreover, "[w]hen steel structures are exposed to high pressure hydrogen at high temperatures, hydrogen molecules dissociate on the steel surface to form atomic hydrogen which readily diffuses into the steel."[6] Prolonged exposure to these conditions can result in corrosion, further weakening the integrity of the metal.

Hydrogen may also be present in steel as a result of metal fabrication and other servicing processes. This results largely from the amount of moisture introduced into the metal. In sufficient quantity, hydrogen can create internal flaws in the steel, which grow and possibly, rupture. Blisters, hairline cracks, snow flakes, voids, microperforation, and porosity are created by liberated hydrogen gas during the cooling process.[7] Vacuum melting, degassing techniques, and providing sufficient time for the solidification of the molten metal to allow liberation of trapped hydrogen constitute good steel making practices that minimize hydrogen content in steel. Reduction of hydrogen diffusivity in steel can be achieved by not only coating steel with barriers, such as cadmium, gold, silver, copper, aluminum, and platinum, but also by implanting certain ions, such as phosphorous, to act as traps on the surface of the steel.[8] Avoiding excessive cathodic cleaning and elements that promote hydrogen entry, such as arsenic, selenium, tellurium, sulfur, phosphorous, tin, mercury, lead, and bismuth reduce the likelihood of hydrogen embrittlement.[9] Because welded zones are particularly susceptible to HIC, properly-stored and clean electrodes and low-hydrogen consumables should be used to decrease the amount of hydrogen content in the weld metal.[10]

Furthermore, a prolonged annealing process, during which metals undergo recrystallization and alteration of its properties, allows time for hydrogen atoms trapped in the metal to escape. Interestingly, high strength steels are more susceptible to hydrogen embrittlement than lower strength steels. This results from quenching and tempering procedures (rapid heating and cooling phases) and from certain metallurgical components.[11]

A reduction in steel ductility because of hydrogen embrittlement will affect the integrity and longevity of steel pipes used in underground hydrogen storage. This is cause for concern since this storage apparatus involves subjecting high strength steel tubes to high pressures and high temperatures, with prolonged exposure to static hydrogen molecules. All the necessary ingredients exist to increase the chance of hydrogen induced cracking.

Similarly, steel structures used in power plants are subject to high temperatures, high pressures, and are in contact with hydrogen-rich aqueous environments (steam). As highlighted through Dayal's and Parvathavarthini's research, hydrogen embrittlement can cause severe damage in power plant steels. The phenomenon of hydrogen embrittlement does not bode well for the technology required in a hydrogen economy, including delivery pipelines, compressors, pumps, storage vessels at filling stations, and storage tanks on vehicles. A solution for the borehole storage design is to use steel that is not the highest grade and/or coat the inside of the inner pipes with hydrogen barriers.

5.1.2 Pipeline Transmission

Additionally, the development of an extensive hydrogen transmission and distribution infrastructure represents one of the most challenging aspects in moving toward a hydrogen economy. An essential ingredient of a hydrogen economy includes a reliable method for transmitting hydrogen gas from the producers to the consumers. These methods include both pipelines and tube trailers; pipelines are the ideal mode of H_2 distribution in a hydrogen economy.

According to the Energy Information Administration (EIA), 99% of all hydrogen gas transported in the U.S. is transported as compressed gas via pipeline. As of 2006, the EIA estimated that 1,213 miles of hydrogen pipeline exist in the U.S., excluding on-site and in-plant hydrogen piping. Moreover, 93% of the hydrogen pipeline network exists in Texas and Louisiana.[12] These states have large chemical users of hydrogen, such as petroleum refineries and plants producing ammonia and methanol.

The natural gas pipeline network in the U.S. offers a good example for how a hydrogen pipeline network might develop in a hydrogen economy. It has been found that a

20%/80% blend of hydrogen/methane can be transmitted in existing natural gas pipelines.[13] California and Pennsylvania are investigating this option to improve their reach of H_2-related facilities.[14] This method, however, becomes less attractive when considering the time and costs of the separation and extraction processes required prior to selling pure hydrogen gas. In contrast to the hydrogen pipelines in Texas, Louisiana, Alabama, Indiana, California, West Virginia, Michigan, Ohio, New York, and Delaware, the natural gas pipeline infrastructure expands into every state and market throughout the U.S.[15] Figure 5.2 depicts this extensive web of natural gas pipelines. As of 2008, the EIA estimated that 302,000 miles of interstate and intrastate transmission pipelines and approximately 1.9 million miles of distribution lines deliver natural gas to consumers throughout the U.S.

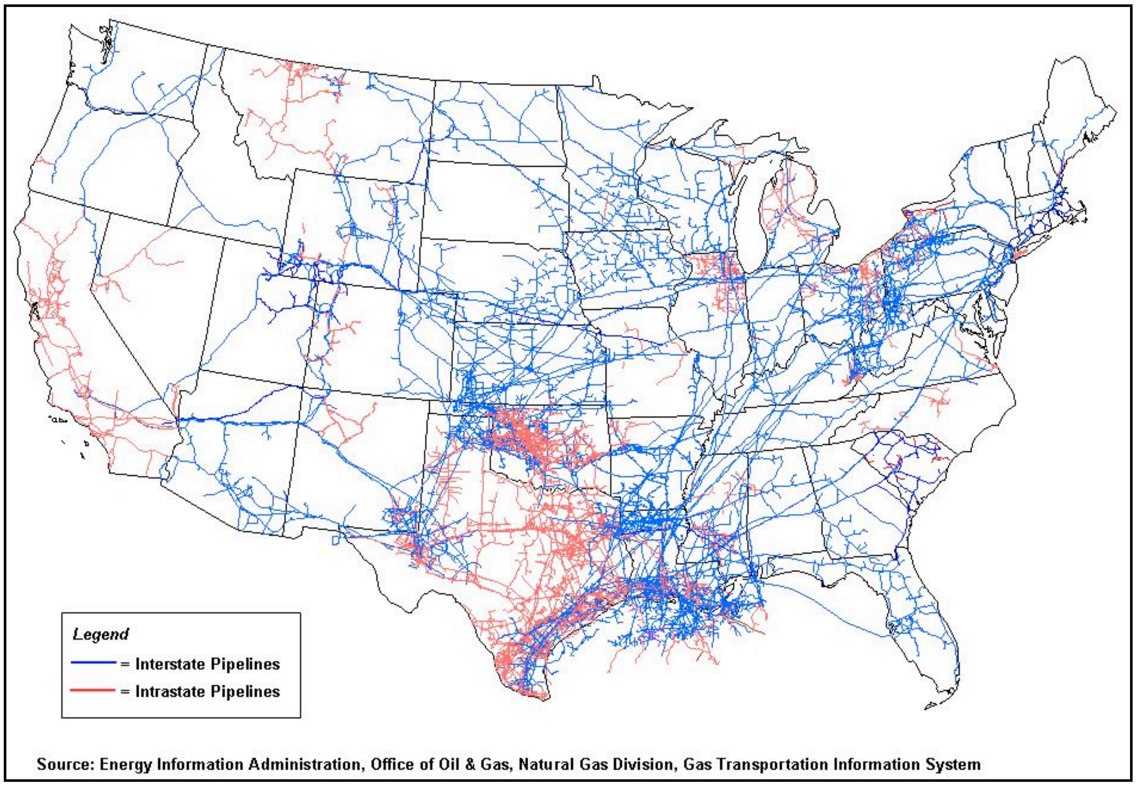

Figure 5.2 U.S. natural gas pipeline network, 2009.[16]

Compressed hydrogen gas pipelines require particular attention that natural gas pipelines do not. They call for special construction techniques and materials, consisting of metals with a high resistivity to corrosion and hydrogen embrittlement. Leak test devices, pressure gauges, and compressor stations that assure continuous forward movement of hydrogen are needed throughout the entire length of the pipeline network. Hydrogen pipelines require more compressor stations than natural gas pipelines because hydrogen gas is more difficult to contain than methane. Because of hydrogen's volatile nature—combustibility—hydrogen gas pipelines also require an elaborate fire prevention, monitoring, and alarm system. Moreover, hydrogen pipelines, more so than natural gas pipelines, call for stringent regulations governing right-of-way width, structures near the pipeline, procedures for pipeline interchanges, pipeline diameter, pipe material, and special safety equipment.

5.2 Economic Considerations

Aside from the costs associated with the actual storage design outlined in Chapter 4, there are multiple economic challenges to the implementation and sustainment of a hydrogen economy. For example, without widespread use of hydrogen, H_2 delivery expenses can be daunting for both those that sell hydrogen gas and for the fueling station owners.

5.2.1 H_2 Delivery Expenses Via Pipeline

Transmission and distribution of compressed hydrogen gas is another cost that must be considered. In a hydrogen economy, delivery of hydrogen to a filling station occurs by rail, tube trailer, or via pipeline. Hydrogen pipelines are the most efficient means of transporting hydrogen gas over long distances, and are the most cost-effective in a robust hydrogen economy. Without a hydrogen economy supporting such an extensive hydrogen pipeline network, it is wiser to develop hydrogen pipelines on a local level first, in areas of high population densities. A centralized, nation-wide hydrogen pipeline grid resembling that of natural gas may emerge as utilization rates increase, and if the government intervenes by way of financial incentives and subsidies.

Costs associated with constructing and operating hydrogen gas pipelines are analogous to those of natural gas pipelines. Labor represents 45% of the total costs for the construction of petroleum-related pipelines, while 26% originates from material costs, 22% from right-of-way expenditures, and 7% on miscellaneous costs.[17] Miscellaneous costs include surveying, engineering, supervision, contingencies, allowances, overhead, and filing fees.[18]

It is safe to assume that the total cost breakdown of constructing hydrogen gas pipelines follows the pattern of petroleum-related pipeline projects. Material and miscellaneous costs may constitute higher percentages for hydrogen pipeline construction projects because of the specialized equipment needed and because of significant regulatory adherence. Material costs are dictated by the weight of the pipe, which is determined by the diameter, wall thickness, and alloy used. Hydrogen pipelines are likely to have smaller diameter pipes than natural gas pipelines, which reduces cost. Hydrogen pipelines, however, require expensive steel alloys and corrosion-retarding coatings in order to avoid embrittlement. Additionally, lower costing, more reliable, and more durable hydrogen compression technology is needed for hydrogen gas pipelines as a result of hydrogen's physical and chemical properties.[19]

Marianne Mintz and her colleagues at Argonne National Laboratory's Transportation Technology R&D Center estimated hydrogen pipeline capital costs in a 2002 report.[20] Their estimate was influenced by pipe diameter and whether or not the pipeline was buried underground. "Cut/cover" installation denotes digging a trench or tunnel and then emplacing a strong overhead support system in order to bear the load of overlying material. As seen in Table 5.1, this system of installing hydrogen gas pipelines is more expensive than trenchless installation, which entails boring tunnels underground. Trenchless pipeline installation minimizes damage to the surface.

Table 5.1 Unit cost of NG & H_2 pipelines

Diameter (in)	Capital Cost of Natural Gas Pipeline ($/mile)	Capital Cost of H_2 Pipeline, Cut/Cover ($/mile)	Capital Cost of H_2 Pipeline, Trenchless ($/mile)
3	200,000	400,000	300,000
9	500,000	900,000	700,000
12	600,000	1,000,000	900,000
14	800,000	1,400,000	1,150,000

5.2.2 H_2 Delivery Expenses Via Truck

Without pipelines throughout the country to distribute compressed hydrogen gas, other forms of delivery must be considered. Augmented by onsite production, trucks typically deliver hydrogen to the few filling stations in the country experimenting with hydrogen fuel. Liquid hydrogen (LHG/cryogenic) is delivered in large, single tankers, which can carry up to 13,000 gallons of liquid hydrogen.[21] Compressed hydrogen gas is transported via tube trailers. This is a tractor/trailer arrangement consisting of between ten to thirty-six compressed-gas storage tubes mounted horizontally on the trailer. Figure 5.3 shows two images of example tube trailers used for compressed hydrogen gas delivery.

Figure 5.3 Shown here are tube trailers, which deliver compressed hydrogen gas. A different number of storage tubes can be arrayed on the trailer.[22]

Tube trailers vary in capacity, and can transport hydrogen gas at varying pressures. Current tube trailers can accommodate 250,000 ft^3 of compressed hydrogen gas, and can pressurize gas from 2,400 psi to 3,600 psi.[23] Although 2,400 psi is the most common pressure rating for bulk hauling of compressed hydrogen gas, the U.S. Department of Transportation (DOT) is expected to increase the allowable pressure of hydrogen gas transported via tube trailers.

As of May 2009, a company named Lincoln Composites and the U.S. Department of Energy were developing high pressure hydrogen tanks for use as storage devices and for use in truck delivery. Their goal is to design and test an assembly of four tanks able to store approximately 600 kg of compressed hydrogen gas at 3,600 psi.[24] Their design can accommodate 800 kg by increasing the pressure to 5,000 psi.[25] Lincoln Composites manufactures hydrogen tanks with high-strength carbon fiber and tough glass filaments, and lines them with their proprietary epoxy resin system and high-density polyethylene. This same technology is being used in their bulk hauling applications.[26]

Without a hydrogen economy, it is difficult to estimate market prices for truck delivery. Delivery of compressed H_2 via tube trailers is a function of frequency and the quantity delivered. Truck delivery costs for the filling station owner can be estimated by assuming several parameters. First, it is assumed that a typical H_2 FCV or H_2 internal combustion engine (ICE) vehicle has a tank capacity of 5 kg, and that each vehicle arrives at the station completely empty. Also, each filling station will allow a 48 hour cushion for truck delivery before the H_2 inventory is planned to empty. Furthermore, it is assumed that market penetration of hydrogen triggers an increase in the number of hydrogen vehicles visiting refueling stations, causes an increase in the amount—and allowable compression—of H_2 hauled by tube trailers, creates a decrease in delivery cost via tube trailers, and triggers a decrease in retail price of H_2 at the pump. In 2010, it is assumed that 15 vehicles per day fill their vehicles with H_2 per filling station in an urban area. Here, an urban area is defined as more than 1,000 people per square mile. Also, according to current DOT standards, tube trailers can carry up to 340 kg of H_2 at 2,400 psi (166 bar). Since a market price for the delivery of compressed H_2 currently does not exist, a high price ($12/kg) and low price ($4/kg) are assumed for 2010. Various reports also attempt to assign a retail price of compressed hydrogen gas at the pump. For this calculation, the retail price of H_2 at filling stations in 2010 is assumed to be $50/kg.

In order to calculate the cost of hydrogen delivery and the resultant profit for a filling station, it is necessary to begin with the amount of H_2 inventory. Although each storage tank can accommodate 1,500 kg H_2, each tank actually holds less than this amount as usable inventory. There must be a minimum volume of gas in the storage pipe in order to permit gas to flow at a minimum desired rate to the surface.

Scenarios 1, 4, and 9 involving the discharge of hydrogen according to specific initial vehicle tank pressures and final fill pressures are used to compute the quantity of usable inventory in each borehole. The percentages of remaining hydrogen from all three scenarios in each borehole are averaged in order to determine the amount of unusable H_2 gas in each borehole. Subtracting this amount from 1,500 kg yields the amount of usable H_2 in each of the three storage chambers. Fifty-two percent (782 kg) of the hydrogen in borehole 1 is usable inventory, while 54% (809 kg) of the hydrogen in borehole 2 is usable inventory, and borehole 3 is calculated to contain 56% (834 kg) usable inventory. Therefore, out of 4,500 kg stored throughout the entire system, only 2,425 kg (54%) is considered usable inventory. This quantity does satisfy the requirement of a 1,500 kg/day filling station.

The amount of hydrogen gas used per day is calculated by multiplying 5 kg H_2 per vehicle tank by 15 vehicles by 7 days. This amount yields 525 kg H_2 that the filling station needs per week. The number of days to empty the hydrogen inventory at the station is calculated by dividing 2,425 kg by 75 kg. This is equal to approximately 33 days. Subtracting the 2-day delivery cushion leaves 31 days. Therefore, every 31 days a tube trailer needs to deliver H_2 to the filling station, assuming a trailer can deliver the entire amount at once. As stated above, this is not possible in the year 2010; only 340 kg can be hauled in one tube trailer. Dividing 525 kg by 340 kg yields approximately 2 deliveries per week. The high price of delivery each week for the filling station is equal to $6,300 (340 kg * $12 * 2), and the low price is $2,100. Subtracting $6,300 from the product of 525 kg and $50 yields $19,950, and subtracting $2,100 from the product of 525 kg and $50 equals $24,150.

Therefore, based on the assumptions listed above and excluding operation and maintenance (O&M) costs, a filling station owner can earn a profit per week of between $20,000 and $24,000. By modifying delivery and retail prices, and accounting for the effects of hydrogen penetration in the market, profit margins for future years can be calculated in a similar fashion. Certainly, the accuracy of these rudimentary computations improve with more specific data, focused assumptions, and a better understanding of the nascent hydrogen market.

5.3 Public Acceptance

Public support of the technologies utilized in a hydrogen economy, such as borehole hydrogen storage, depends on several interrelated factors. First, demand for hydrogen as an energy carrier must exist in society. Secondly, implementing complex hydrogen-related technologies, such as production facilities, storage devices, filling stations, distribution networks, and hydrogen vehicles must make economic sense. A hydrogen economy faces stiff competition from the widespread use of conventional fossil-based fuels, and the overwhelming experience and infrastructure linked to that industry. Lastly, a hydrogen economy does not appear to be an extraordinarily appealing alternative to fossil-based fuels when analyzing its life-cycle emissions and effects on air quality. This last issue is inseparable from the technical challenges associated with hydrogen systems.

5.3.1 Lack of Demand

Large investments in hydrogen projects are currently not economically justifiable because of several unresolved technical issues and an overall lack of demand. Various technical challenges are discussed in a previous section. A frequently asked question is whether or not H_2 filling stations and related infrastructure must precede the production and sell of hydrogen vehicles. Prior to investing in hydrogen storage ventures, investors need to know there is adequate demand to turn a profit. Furthermore, aside from demonstration purposes, vehicle companies do not manufacture hydrogen vehicles on a large scale without a strong probability of demand for their product.

5.3.2 Improvements to Information Flow

The flow of information regarding hydrogen uses and safety is another aspect affecting public support. It can be argued that people, armed with accurate information, would accept the implementation of a hydrogen economy. They then would elect public officials that represent this vision. However, without government intervention via incentives and subsidies, current market forces do not support the emergence of a hydrogen economy.

5.3.3 Safety Concerns

Linked to the problem of information flow, public support of hydrogen-related technologies also depends on adequately addressing issues of safety. Safe practices throughout the production, storage, transmission, and use of hydrogen are essential to a hydrogen economy. Handling compressed hydrogen gas can be a hazardous affair as a result of its physical and chemical properties. Hydrogen gas is invisible, odorless, difficult to contain, reacts with most elements, and highly combustible. The gas also burns as an invisible flame. Understandably, there is reason for concern when using and exchanging compressed H_2.

Although not standardized to the extent witnessed in the petroleum industry, hydrogen projects are becoming increasingly regulated. Building codes and technical standards are essential elements for the deployment of hydrogen technologies. Enabling the commercialization of hydrogen requires federal, state, and local governments to not only recognize codes, but also enforce them. Several international and national regulatory organizations offer important codes and standards dealing with the use, storage, and delivery of compressed hydrogen gas.

The U.S. DOE works closely with these code development bodies, industry experts, officials, and scientists in drafting regulations. The International Code Council (ICC) is a membership association that provides comprehensive building safety and fire prevention codes and standards used in commercial and residential structures. All fifty states and the District of Columbia have adopted their codes, and many U.S. government agencies implement ICC codes throughout the world. Hydrogen-related facilities must utilize the

ICC's International Fire Code during engineering and construction. The latest version of the Fire Code was published in 2009.[27]

Another organization which develops and publishes codes relevant to a hydrogen economy is the National Fire Protection Association (NFPA). Their code numbers most applicable to hydrogen storage, distribution, and use include: NFPA 52, Vehicular Gaseous Fuel Systems Code; NFPA 55, Compressed Gases and Cryogenic Fluids Code; NFPA 30A, Code for Motor Fuel Dispensing Facilities and Repair Garage. Codes 52 and 55 are available in 2010 editions and the current code 30A appears as a 2008 edition. The NFPA plans on disseminating code NFPA 2 in 2011. This proposed document is titled Hydrogen Technologies Code and will deal more specifically with hydrogen systems than NFPA's other available publications.[28]

The Compressed Gas Association (CGA) is an additional body which publishes codes relating to the construction of hydrogen facilities. This organization mainly focuses on promoting safe practices and developing safety standards for the industrial gas industry. The CGA has a technical committee dedicated solely to hydrogen technologies. Publication identification CGA G-5 includes topics such as hydrogen vent systems and high pressure hydrogen gas piping systems at consumer locations.[29]

The transportation of compressed hydrogen gas in small cylinders, as well as large cylinders stacked horizontally on tube trailers is regulated by the U.S. DOT. Appropriate cylinder markings, issuance of permits, pressure relief devices, and carriage of hazardous materials on public highways are subjects included in DOT Title 49, Parts

107, 173, and 177. Section 300, Subpart G of Part 173 outlines the requirements for preparation and packaging compressed gases.[30]

Documents published by the aforementioned organizations focus on minimizing hazards associated with hydrogen, and they facilitate the permitting process for hydrogen fueling stations and other hydrogen projects. Tables 5.2, 5.3, and 5.4 provide the minimum safe distances from people, objects, and certain equipment to hydrogen systems. These distances are referenced in designing the borehole H_2 storage apparatus.

Table 5.2 Minimum separation distances from outdoor gaseous H_2 systems to exposures.[31]

Distance (ft)	From
35	Lot lines
15	People (other than servicemen)
15	Structures
35	Air intakes such as HVACs, compressors)
15	Overhead utilities
35	Ignition sources such as open flames & welding
15	Parked vehicles
15	Above ground vents or exposed piping & components of
15	Ordinary combustibles
15	Heavy timber, coal, or other slow burning combustible solids

Table 5.3 Minimum separation distances for outdoor gaseous H_2 dispensing systems.[32]

Dispensing System	Distance (ft)	From
Dispenser	10	Nearest important building or line of adjoining property
Dispenser	10	Nearest public street or public sidewalk
Dispenser	10	Nearest railroad
Point of transfer*	10	Important buildings except those structures with exterior
Pont of transfer	35	Hydrogen storage containers

* Location where H2 is supplied to the filling station from the method of distribution (pipeline or tube trailer)

Table 5.4 Minimum separation distances from hydrogen systems to electrical installations.[33]

Distance (ft)	From
15	Hydrogen storage containers
15	Area containing compression and ancillary equipment
5	Dispensing equipment

Additionally, several codes and standards applicable to the hydrogen storage apparatus designed in this research are worth noting:

• [NFPA 52 5.3.4.1] “Pressure vessels shall be manufactured, inspected, marked, and tested in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code”

• [NFPA 52 5.8] Fuel line “pipe, tubing, fittings shall be suitable for hydrogen service and for maximum pressures and minimum and maximum temperatures.”

• [NFPA 52 5.8.4.1] “Piping joints made with tapered threaded pipe and sealant shall not be used in hydrogen service above 3,000 psi (20.7 MPa).”

• [NFPA 52 5.10.1] “Hoses shall be constructed of or lined with materials that are resistant to corrosion and exposure to hydrogen.”

• [NFPA 52 5.11.1] “Fueling nozzles for compressed hydrogen gas service shall be listed or approved in accordance with SAE J2600” (Society of Automotive Engineers (SAE) document J2600 titled Compressed Hydrogen Surface Vehicle Refueling Connection Devices).

• [NFPA 52 9.2.3-3.2] Hazard analysis shall be conducted by a qualified engineer on the fire “protection and suppression systems, detection systems, ventilation,” and the “potential failures in hoses, nozzles, dispensing equipment.”

• [NFPA 52 9.2.10.2] “Compression and gas processing equipment shall have pressure relief devices that limit each stage pressure to maximum allowable working pressure for the compression cylinder and piping associated with that stage of compression.”

• [NFPA 52 9.2.14 & 14.1] “Dispensing equipment shall be provided with gas detectors, leak detection, flame detectors such that fire and gas can be detected at any point on the equipment.” These “detectors shall be maintained and calibrated annually.”

• [NFPA 52 9.3.1.2] “Equipment is to be installed on foundations with anchoring systems.”

• [NFPA 52 9.4.1] “Dispensing operations shall be performed by an operator who has been qualified by training to perform functions necessary in filling operations as described by manufacturer’s operating instructions.”

• [NFPA 52 9.4.3.2.2 & 2.5] “Dispenser shall be equipped with an automatic shutoff control to shut down source of fuel when maximum fuel quantity reached or vehicle filled to capacity,” and the “maximum refueling rate” shall not exceed 2 kg/min (4.4 lbs/min, 845 ft^3/min, 24 m3/min).

• [NFPA 52 9.4.4.1 & 4.2 & 5.1] A fire alarm system is required in the dispensing area, with a manual fire alarm box no more than 20 ft but less than 100 ft from the dispensing station. “Actuation of the fire detection system in the dispensing area shall shut down the gas flow from the dispenser and stop flow of gas into the piping system.”

• [NFPA 52 9.4.7.1] “Hydrogen gas piping used to transport H_2 between the bulk hydrogen compressed gas storage system and a dispenser at a fast-fill station shall have a valve that closes when (1) power supply to dispenser is shutoff and (2) any emergency shutdown device (ESD) at the refueling station is activated."

• [NFPA 52 9.4.7.3.1] "Activation or failure of the following systems shall automatically shut down the gas flow from the dispenser: (1) gas detection system; (2) fire alarm system; (3) fire detection system; (4) ESD; (5) sensors or controls used to prevent over-temperature or over-pressurization of the on-board fuel container; (6) required ventilation systems; (7) dispenser leak monitoring system."

• [NFPA 52 9.4.7.4] "Dispenser enclosures or housing shall be equipped with a gas detection system, which shall activate when a maximum of 25% of lower flammable limit (LFL) is detected (1% H_2 in air)," triggering an on-site alarm. The LFL report must be shown on some display for the operator to view.

• [NFPA 52 9.7.1] Pressure regulators must be installed in such a manner as not to be affected by "freezing rain, sleet, snow, ice, mud, insects, and debris."

• [NFPA 52 9.8] Pressure gauges must be installed "to indicate compression discharge pressure, storage pressure, and dispenser discharge pressure."

• [NFPA 52 9.9] Piping and hoses must be installed in such a manner as to protect them from the effects of expansion, contraction, jarring, vibration, settling, and corrosion.

• [NFPA 52 9.9.1.2] Underground piping must be greater than 18 inches below ground surface.

• [NFPA 52 9.9.1.4.12] "A pipe thread jointing material impervious to the action of H_2 …must be applied to all male pipe threads prior to assembly."

• [NFPA 52 9.11.2] "Compressor discharge line supplying storage container shall be equipped with a backflow check valve to prevent discharge of the H_2 from the container in case of a rupture of line, hose, or fittings."

• [NFPA 52 9.16.2.6 & 2.7] A system of “controllers…shall be designed to verify the integrity of the fuel hose, breakaway nozzle, and receptacle by pressurizing these components to at least the vehicle back pressure and checking pressure drop over a period of at least 5 seconds prior to start of fueling.” These “integrity checks shall be repeated at 3,000 psi increments up to the final fill pressure.”

• [NFPA 55 10.8.1] “Compression…equipment shall have pressure relief devices that limit each stage pressure to the maximum allowable working pressure of the compression cylinders and piping associated with that stage of compression.”

• [NFPA 55 10.8.4.5] “The pressure on the compressor discharge shall be monitored by a control system.”

• [NFPA 55 10.5.1] Prior to acceptance and initiating operation of the fueling station, all piping installations shall be leak tested, inspected, and pressure tested in accordance with ICC International Fuel Gas Code (IFGC) Section 705.

These codes and standards mandate several other topics. For example, NFPA 52 requires that hydrogen equipment be maintained by personnel trained on leak detection procedures and by corrosion experts certified by the National Association of Corrosion Engineers (NACE). Both NFPA 52 and 55 require that the valves, controls, safety devices, and instrumentation be above ground, and accessible to only authorized personnel. Manual emergency shutdown devices and portable fire extinguishers are also mandated in the dispensing area. Additionally, vent piping is required in areas of possible hydrogen gas buildup, especially the pump housing and the compressor/manifold housing. A significant amount of redundancy in regulations exist between the International Fire Code, CGA G-5, NFPA 52, NFPA 55, and NFPA 30A.

The Office of Energy Efficiency and Renewable Energy (EERE), as part of the DOE Hydrogen Program, addresses safety in several ways. A web-based hydrogen safety course for fire, law enforcement, and emergency medical personnel is provided on the DOE website. The Hydrogen Program's website also contains a hydrogen safety bibliographic database, including reports, articles, books, and resources dealing with hydrogen leaks, embrittlement, fuel cell technology, accidents involving hydrogen, and safe operating and handling procedures. In addition, the H_2 Safety Snapshot quarterly bulletin is available to download. This publication features best practices and lessons learned regarding safety. The website not only highlights pertinent codes and standards required for permitting most aspects of hydrogen fuel stations, but also offers an online training course for those wishing to learn about fuel cell technology basics, applications, and permitting H_2 facilities.

Considerable emphasis placed on hazard management throughout all codes and standards should mollify any safety concerns the public has regarding hydrogen facilities in the U.S. Moreover, it is predicted that this hydrogen storage design yields greater public support than conventional H_2 storage devices at filling stations. The novel borehole storage technique minimizes human exposure to H_2 volatility.

5.3.4 Environmental Impact

In addition to safety, people's view of the overall benefit a hydrogen economy has on the environment affects public acceptance. Research and development continue to improve the technology used in hydrogen systems in order to reduce its impact on the environment. Although water is the only substance emitted from the tailpipe of hydrogen vehicles, emissions from hydrogen's production and transportation sectors are much less benign. This fact is revealed through a life-cycle analysis of the hydrogen molecule.

A life-cycle approach traces certain emissions upstream and downstream, and is often carried out to assess the overall benefit and efficiency of specific technologies. Life-cycle analysis typically addresses CO_2 emissions and emissions of pollutants such as carbon monoxide (CO), nitrogen oxide compounds (NO_x), volatile organic compounds (VOCs), and particulate matter. Produced from combustion, nitrogen oxides are components of smog, and VOCs include a host of organic chemicals and solvents that vaporize readily into the atmosphere. All of these pollutants can be toxic to living organisms in excessive amounts.

The life-cycle analysis relating to a hydrogen economy's supply chain is more complex than initially realized. Hydrogen is a secondary energy source—an energy carrier—and, therefore, must be produced from a primary energy source. In the case of hydrogen production, natural gas is currently the primary energy source. Figure 5.4 depicts three different natural-gas based hydrogen supply chain scenarios, and highlights sources of emissions along the way.

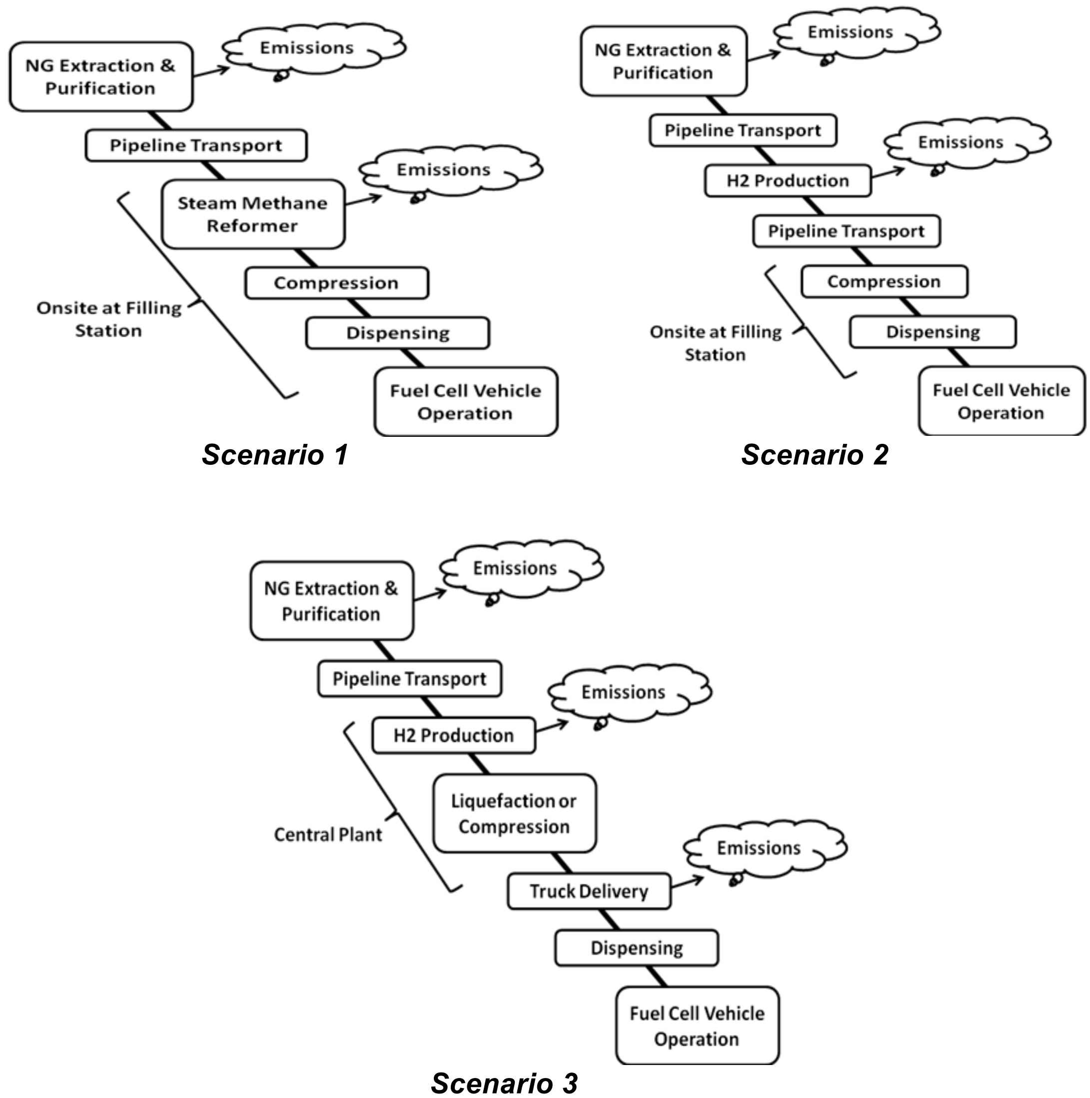

Figure 5.4 Hydrogen supply chain from natural gas production and related emissions: These flowcharts depict three separate hydrogen supply chain scenarios produced from natural gas and corresponding emissions. The charts are useful in analyzing lifecycle emissions from hydrogen production and delivery.[34]

Varying concentrations of CO, CO_2, NO_x, VOCs, and particulate matter are emitted during natural gas extraction and purification, steam methane reforming (SMR), and during hydrogen delivery. One scenario illustrated in the figure above involves H_2 production at a natural gas plant or at a petroleum refinery. Another scenario entails H_2

production from a steam methane reformer located at the filling station. The concentrations of pollutants emitted from the on-site SMR are less than the amount emitted from large plants and refineries.[35] However, the SMR located at the filling station not only receives its fuel from some pollutant-emitting delivery method, but it also may be supplemented with additional H_2, arriving at the station via liquefied or compressed-gas transport.

Electricity production, occurring further upstream on the hydrogen supply chain, also contributes harmful emissions to the atmosphere. Figure 5.5 reveals the sources of emissions during electricity production.

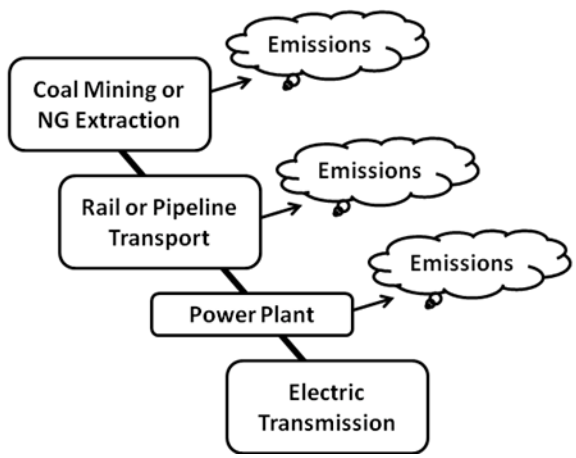

Figure 5.5 Electricity production and related emissions: The process of producing electricity emits pollutants and CO_2 into the atmosphere. These emissions must be accounted for in the lifecycle emissions analysis of the production and delivery of hydrogen and gasoline.[36]

Emissions are released during coal extraction and during transportation of coal to power plants via railway. For example, coal from the Powder River Basin in Wyoming travels great distances to supply areas of high demand throughout the country. At the power plants, electricity generation entails the combustion of coal or natural gas. This process emits pollutants into the atmosphere.

Electricity on the grid powers, essentially, all stages of hydrogen's supply chain. Electricity powers the equipment used for natural gas extraction, as well as the pumps used to maintain natural gas flow during transport in pipelines. A significant amount of electricity is also used in H_2 production plants and in steam methane reformers. Electricity provides the energy used to liquefy and/or pressurize H_2, and powers the pumps along hydrogen pipelines.

Despite the emissions released throughout the hydrogen supply chain, research has found that the use of fuel cell vehicles has less impact on air quality than vehicles which burn fossil fuels. An analysis of lifecycle emissions from the gasoline/diesel supply chain is similar to that of hydrogen (refer to Figure 5.6). However, because of the actual combustion of gasoline and diesel in vehicles, the overall lifecycle emissions are greater than that of hydrogen. Hydrogen fuel cell vehicles release only water vapor, but fossil fuel combustion from the transportation sector in the U.S., for example, has contributed more CO_2 emissions since 2000 than any other end-use sector. In 2008, the transportation sector accounted for approximately 1,930.1 million metric tons of CO_2 released into the atmosphere, more than the residential, commercial, and industrial sectors.[37]

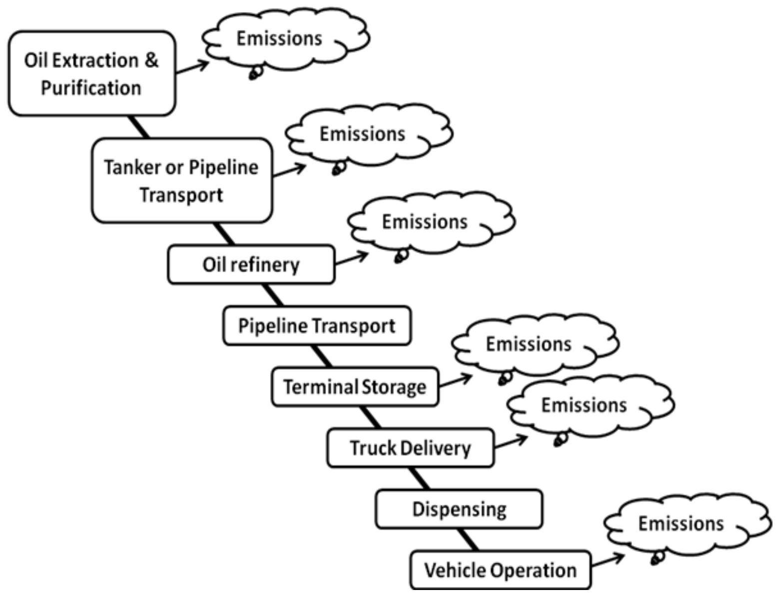

Figure 5.6 Gasoline supply chain and related emissions: The total amount of pollutants emitted from the extraction, transport, and refining of oil, and the delivery and combustion of gasoline/diesel is greater than those emitted from the extraction of natural gas, and the production and delivery of hydrogen.[38]

A study by Guihua Wang and his colleagues shows that the impact on air quality is greater from gasoline- and diesel-fueled vehicles than from hydrogen fuel cell vehicles. Their research compares the lifecycle emissions from light duty gasoline vehicles and hydrogen fuel cell vehicles in the Sacramento, California metropolitan area for scenarios in 2005 and 2025. Based on population trends, they make estimates for the number of vehicles city-wide and for the number of filling stations needed to service both gasoline and fuel cell vehicles. They also assume hydrogen demand per day, fuel economy, miles traveled, hydrogen consumption per vehicle, hydrogen station size, and liquefied H_2 truck capacity. Wang and his colleagues utilize existing air quality monitors located throughout the region that test for CO, NO_x, VOCs, and particulate matter concentrations.

They conclude that the hydrogen flow pathway involving H_2 production at a central plant with pipeline delivery to filling stations reduces pollution more than the other two hydrogen supply scenarios, and certainly more than that of gasoline vehicles. Flow pathways for gasoline vehicles produce higher atmospheric concentrations of all criteria pollutants than all three hydrogen scenarios: 273 times the CO concentration, 3.5 times the NO_x concentration, 88 times the VOC concentration, and 8 times the concentration of particulate matter.[39]

Although this study concentrates on one particular metropolitan area in the U.S. and makes several assumptions about hydrogen's use by fuel cell vehicles, it shows that, given enough penetration of the transportation sector, hydrogen systems have the ability to emit less harmful pollutants than the status quo. In summary, a hydrogen economy is appealing to the public because it has less impact on air quality.

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CHAPTER 6: CONCLUSION

The proposed underground hydrogen storage method takes advantage of the technical expertise gained through decades of experience in the oil and gas field. Research into drilling boreholes and developing materials required for this project can be avoided because the knowledge and resources are readily available throughout the oil and gas industry. For example, engineers in the oil and gas field deal with hydrogen-rich gas flowing through steel tubes on a daily basis. They also encounter hydrogen sulfide-induced embrittlement of steel pipes on a regular basis, and find ways to remedy the cracking.

In this storage design, an inner and an outer pipe are run the entire length—depth—of each of the three boreholes. The inner tubing represents the actual compressed H_2 storage container, while the outer pipe acts a sheath, protecting the inner pipe and offering containment in case of gas leaks. The volume in each storage tube is determined by the mass of H_2 required in each borehole to accommodate a hydrogen vehicle filling its 5-kg tank to capacity once per week. With a filling station sized for use of 1,500 kg H_2 per day, 1,500 kg of H_2 is required in each borehole because approximately 54% (2,425 kg) of the total amount of stored hydrogen (4,500 kg) is considered usable inventory. By compressing hydrogen gas to 4,000 psi in the first borehole, 8,000 psi in the second, and 12,000 psi in the third, the H_2 dispenser on the surface can take advantage of the cascading method when filling each vehicle. The next, higher pressure storage tube is able to compress H_2 into a vehicle's tank until reaching its maximum fill pressure. Thus, this cascading technique eliminates the need for a compressor to fill each on-board tank to capacity when vehicles arrive at the pump.

The depth of each borehole is calculated using the volume requirements from the scenario-based analysis. Hydrogen gas compressed to 4,000 psi is stored in a borehole 7,781 ft deep. Gas compressed to 8,000 psi is stored in a container reaching into the subsurface 5,893 ft. The storage pipe containing H_2 compressed to 12,000 psi resides in a borehole 5,895 ft deep.

The hydrogen equipment at the surface occupies an area approximately 40 ft long by 10 ft wide, protected by a metallic structure. A transfer point at one end of the structure is equipped to receive H_2 from tube trailers. Hydrogen gas flows through the inlet manifold and into a heavy-duty hydrogen compressor. H_2 exits the compressor and is sent into one of three boreholes using a system of valves in the outlet manifold. On demand, H_2 is released from one of the storage boreholes to supply hydrogen to the dispenser.

A rudimentary cost estimate of this storage design reveals a total cost of approximately $2.58 million. This figure includes the cost of drilling and completion, steel pipe, a hydrogen compressor, and miscellaneous equipment, such as valves, regulators, gauges, additional tubular piping, electrical equipment, and safety devices. This figure does not include the cost of the actual dispenser and customer interface, and the cost of the overhead metallic structure. Also, this dollar amount does not account for expenses related to the operation of the filling station, such as the cost of hydrogen supply via tube trailers or pipeline, electricity costs, employee salaries, and annual required maintenance costs.

Borehole storage faces challenges to its implementation. The impact of hydrogen embrittlement in steel pipe, and the challenges associated with pipeline transmission represent the main technical issues. Economically, hydrogen systems, including underground H_2 storage devices, face stiff competition from systems using conventional fossil fuels. Currently, a stalemate exists between sponsors willing to invest in hydrogen facilities only if extensive manufacturing of hydrogen-powered vehicles occurs, and those manufacturers willing to mass-produce hydrogen vehicles only if there is significant, nation-wide investment in hydrogen facilities.

Related to the fiscal challenges is the lack of public support. Demand for an underground hydrogen storage system is low because a hydrogen economy is difficult to justify financially. People may perceive such a storage technique as risky because of a lack of codes and standards governing the production, transportation, storage, and use of hydrogen as a fuel. However, the hydrogen industry is not completely uncharted; there are several code development organizations and federal agencies committed to providing building codes and technical standards for the purpose of minimizing hazards related to hydrogen. For example, these codes and standards mandate the use of specialized safety equipment and minimum safe distances from hydrogen systems.

Furthermore, it is difficult to sell a ‘clean energy’ to the public with mediocre results from hydrogen’s life-cycle emissions analysis. Criteria pollutants and CO_2 are emitted into the environment from the production, transportation, and use of hydrogen in most applications. One approach to minimizing harmful emissions is to use the electricity produced from photo voltaic solar cells or wind mills to power large-scale electrolyzers nearby filling stations. Nevertheless, research does demonstrate that hydrogen systems and facilities impact air quality less than the use of conventional fossil fuels.

If and when the U.S. transitions to an economy that favors the use of hydrogen as a fuel source, the borehole storage system described herein is a feasible solution for on-site compressed H_2 storage. This design is capable of storing a larger inventory of hydrogen more efficiently and safer than other hydrogen storage projects.

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VITA

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